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# **Hydrogen as a fuel source for vehicles.**

## **Options for a hydrogen bus energy supply system based on Economic & Environmental considerations**

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**Submitted for Doctorate of Philosophy**

**Faculty of Mathematics, Computing and**

**Technology**

**The Open University**

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*Hydrogen as a fuel source for vehicles.  
Options for a hydrogen bus energy supply system based on  
Economic & Environmental considerations*



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## Abstract

Hydrogen is a potential solution to transport's environmental challenge. However, current production and delivery methods may make hydrogen no more environmentally friendly than many other transport fuels. Transporting hydrogen is difficult and energy intensive. Given the right production and delivery system, a future Hydrogen economy could address environmental issues and other major areas of concern such as energy security and shortage.

This research focuses on the viable pathways to deliver hydrogen for fleet vehicles. Drawing on a range of sources, including the recent Clean Urban Transport for Europe (CUTE) demonstration projects, the research models a set of pathway options comparing:-

- Economics – the cost of hydrogen for fleet vehicles compared to a base diesel reference case.
- Environmental issues - CO<sub>2</sub> equivalent emissions for each of the pathways.

Overall, the results of this research will show that:-

- Hydrogen is potentially competitive with diesel in terms of cost of production, but not for cost of distribution. Overall distribution costs make hydrogen pathways more expensive than diesel.
- Localised production of hydrogen is not competitive with centralised production at present, so it is likely that a hydrogen distribution system is going to be needed. It is possible that future localised production systems may be competitive but would depend on reduced capital equipment costs.
- The cheapest hydrogen pathways may not be the pathways with the least emissions.
- The storage of hydrogen appears to be a major part of distribution costs.
- Gaseous hydrogen delivery by road tanker can only meet small niche markets.

- Transporting hydrogen in liquid state is not viable for any supply chain lengths and demands



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- Transporting hydrogen in liquid state is not viable for any supply chain lengths and demands in the UK (within the boundaries of this model ie: 200km and 5,000kg / day).
- Gaseous hydrogen delivery by pipeline is needed if a reasonable uptake is sought. This would require significant investment.

## Preface

At the time of starting this research degree, I was employed at Air Products, a major industrial gas supplier in their HYCO (hydrogen and carbon monoxide) product supply team. My interest in this subject started during this period with the realisation that hydrogen had the potential to become an alternative energy carrier in the 21<sup>st</sup> century and not just another industrial gas used in chemical processes. At the same time, the first hydrogen powered concept vehicles were beginning to appear. It occurred to me if vehicles were to be powered by hydrogen in the future, a significant amount of hydrogen would be needed and probably distributed. With my experience and knowledge of hydrogen production and supply, I realised that distribution could potentially be a major obstacle to hydrogen economy. It is the combination of these two factors that has inspired this research work.

## Declaration

The following publications have been produced by the author and in the case of the UTSG papers, results used in chapter 8 of this thesis:-

### **Tilting at Hydrogen Tanks in Hornchurch (Berridge C, 2004, p57)**

BERRIDGE C. (2004), 'Tilting at Hydrogen Tanks in Hornchurch'. *Renew on line*, Nov - Dec 2004 volume 52, p152, available from <http://eeru.open.ac.uk/natta/renewonline/rol52/9.htm>, (accessed 11th July 2009)

### **Exploring options for a hydrogen fuel infrastructure (Berridge C, 2008)**

BERRIDGE C. (2008), 'Exploring options for a hydrogen fuel infrastructure'. *UTSG 40th Annual conference*, Portsmouth, Hampshire, January 5th to 7th 2008, publisher - UTSG

### **Modelling pathways for a hydrogen fuel infrastructure system (Berridge C, 2009)**

BERRIDGE C. (2009), 'Modelling pathways for a hydrogen fuel infrastructure system'. *UTSG 41st Annual conference*, London, January 5th to 7th 2009, publisher - UTSG

# Clarifications

As with many research reports, this thesis contains a significant quantity of facts and figures which are referenced from other sources of data. Data quoted may vary according to the date of the paper, currency conversions etc. This can pose a problem for readers, particularly with respect to historical costs. It is further complicated by the variety of ways in which forms of energy can be quoted. For example, diesel in litres, natural gas in therms or cubic metres, electricity in kilowatt hours and solid fuels in kilograms. This is particularly relevant, as different types of fuels do not have the same energy values by mass or volume. For example, 1 litre of diesel does not contain the same amount of energy as 1 litre of hydrogen. The following clarifications are intended to aid the reader to understand the basis of any conversions used in this research:

**Historical costs** In general, references to costs are taken as historical, direct from the cited source of data. For example, if a cost of hydrogen is quoted as £1.50 per kg in 2001, it is the cost at that time.

**Currency conversions** Occasionally, costs need to be converted from different currencies. When this has been necessary, the following conversion factors used have been used.

$$£1.00 = \$1.90 = €1.40.$$

**Inflation costs** Some of the data used in this research has been obtained from relatively old papers (eg: 10 years old). Whilst the data is still valid it often needs to be corrected for inflation. Where inflation rate adjustments have been made it is on the basis of an assumed rate of 2% per annum ie:

$$\text{Cost } £1.00 \text{ in 2002} = \text{Cost } £1.15 \text{ in 2009}$$

Where inflation costs have been adjusted with respect to time, notes have been added to the effect: e.g.: “**adjusted to 2009 costs**”.

**Taxes and duties** In general, all cost calculations are based on the energy cost before any taxes are added. For example, if diesel is sold retail at £1.10p / litre, the actual cost used in the calculation is after the deduction of fuel duty and value added tax (VAT). This enables a valid comparison to be drawn between the fuels and creates an “even playing field”.

**General energy** There are several ways to describe fuels and energy carriers. By mass (kg),

**conversions**    volume (NM<sup>3</sup>) and energy (MJ).Where NM<sup>3</sup> is defined as “normal” metres cubed.  
The definition of “normal” being at 1.013 Bar absolute and 0 °C. Typical values  
used are:-

$$\text{Hydrogen} - 1 \text{ kg} = 11 \text{ NM}^3 = 120 \text{ MJ}$$

$$\text{Diesel } 1\text{kg} = 0.0012 \text{ NM}^3 = 43 \text{ MJ}$$

<b>Cost per unit of mass (£/kg)</b>	This is used to compare cost for the same type of fuel. For example transporting hydrogen by pipeline or road tanker.
<b>Cost per unit of energy (£/GJ)</b>	This is necessary when comparing different types of fuel, for example transporting hydrogen versus diesel, as fuels tend to have different energy values based on mass e.g.: hydrogen = 120 MJ/kg whereas hydrocarbons ≈ 45 MJ/kg.
<b>Cost per distance of bus travel (£/100km)</b>	This measure was developed for when comparing complete pathways from production to end use, particularly where different fuels and / or vehicle technologies are used. For example, Fuel Cell Vehicles (FCVs) using hydrogen compared to Internal Combustion Vehicles (ICVs) using diesel. In this situation it is not appropriate to quote in £/GJ as the two technologies have different efficiencies. It is a useful measure of where hydrogen is at the time of writing in terms of cost when compared with other types of fuel such as diesel.
<b>Equivalent diesel forecourt price (£ / litre)</b>	<p>Whilst “cost per distance of bus travel” is a useful measure to compare different fuels and technologies, it is not a particularly helpful measure when considering future predictions of costs and technology developments. During the latter stages of this research, the term “equivalent forecourt diesel cost” is introduced to put the actual cost of hydrogen into context.</p> <p>“The equivalent forecourt cost of diesel” is the price that diesel would have to reach for hydrogen to be price competitive. It is best explained by example:-</p> <p>Hydrogen pathway = £125 / 100km of bus travel</p> <p>Diesel pathway = £100 per km of bus travel (based on diesel at £1.10 per litre)</p> <p>If the diesel cost is then increased until the two pathways are equal, we have what is referred to here as the “equivalent forecourt cost of diesel”.</p> <p>The price of diesel at £xx / litre is inclusive of VAT and fuel duty</p>

## Glossary

<b>Distribution system</b>	Method by which fuel is transported from the point of production to the point of use.
<b>Energy carrier</b>	An energy carrier is derived from a fuel, eg: Electricity (is an energy carrier) which is derived from Natural Gas (which is a fuel).
<b>Energy vector</b>	As energy carrier.
<b>Scenario</b>	The term scenario is used in this research to define a specific set of conditions, generally used in the modelling chapters 6, 8 and 9 to describe a particular analysis or test. For example varying hydrogen pathways according to demand and supply chain length.
<b>Infrastructure</b>	Component(s) of the supply and distribution system, typically compressors, tankers, pipelines etc.
<b>Pathway</b>	Encompasses the whole cycle of a hydrogen supply and distribution system from production, delivery, storage and loading onboard vehicles. It does not include on board fuel use.

## Abbreviations

	Bar denotes a unit of pressure equal to 1 atmosphere (approx 14.5 pounds per square inch)
<b>bar</b>	(a) denotes absolute pressure (g) denotes gauge pressure. ie: 1 Bar (a) = 0 Bar (g)
<b>BEV</b>	Battery powered Electric Vehicles
<b>CAPEX</b>	CAPital EXpenditure – Capital cost of equipment
<b>CCS</b>	Carbon Capture and Storage
<b>CDCT</b>	Camelford and District Community Transport
<b>CNG</b>	Compressed Natural Gas
<b>CNT</b>	Carbon Nano Tubes
<b>CREST</b>	Centre For Renewable Energy Systems Technology
<b>CUTE</b>	Clean Urban Transport for Europe
<b>ECTOS</b>	Ecological City Transport System
<b>EU</b>	European Union
<b>FCV</b>	Fuel Cell Vehicle
<b>GH<sub>2</sub></b>	Gaseous Hydrogen
<b>GNF</b>	Graphite Nano Fibres
<b>GWP</b>	Global Warming Potential
<b>HaRI</b>	Hydrogen and Renewables Integration project
<b>Hythane</b>	A mixture of hydrogen and hydrocarbon gases
<b>ICE</b>	Internal Combustion Engines
<b>ICV</b>	Internal Combustion Vehicle
<b>IET</b>	Institution of Engineering Technology
<b>LCA</b>	Life Cycle Analysis
<b>LDS</b>	Local Distribution system (with respect to gas national grid)
<b>LH<sub>2</sub></b>	Liquid Hydrogen

<b>LHV</b>	Lower Heating Value, also known as the Nett calorific value. Usually expressed in terms of MJ/kg and is the amount of energy released by combusting a specific quantity of the fuel. It assumes that latent heat of vaporisation of the water in the fuel is not recovered.
<b>Li ion</b>	Lithium Ion (battery)
<b>LNG</b>	Liquefied natural gas
<b>LPG</b>	Liquefied Petroleum Gas
<b>LTS</b>	Local Transmission system (with respect to gas national grid)
<b>Ni Cad</b>	Nickel Cadmium (battery)
<b>Ni MH</b>	Nickel Metal Hydride (battery)
<b>NM<sup>3</sup></b>	Normal metre cubed (for gases at 0 °C and 1.013 bar absolute pressure)
<b>NTS</b>	National Transmission system (with respect to gas national grid)
<b>ONS</b>	Office of National Statistics
<b>OPEX</b>	OPERating EXpenditure – usually expressed a % of CAPEX per annum
<b>PEM</b>	Proton Exchange Membrane (Fuel Cell)
<b>POCP</b>	Photochemical Ozone Creation Potential
<b>POX</b>	Partial OXidation (reforming process)
<b>PSA</b>	Pressure Swing Adsorption
<b>PURE</b>	Promoting Unst Renewable Energy
<b>ROW</b>	Rights Of Way – a term used in pipeline installations
<b>SCF</b>	Standard Cubic Feet
<b>SMR</b>	Steam Methane Reforming (process)
<b>STEP</b>	Sustainable Transport Energy for Perth
<b>UTSG</b>	Universities Transport Studies Group
<b>VAT</b>	Value Added Tax



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# CHAPTER 1 INTRODUCTION

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The research in this thesis addresses issues associated with hydrogen as a fuel source for vehicles, specifically fleet vehicles (such as buses), and the necessary fuel supply and distribution system associated with it. At the time of writing, there are relatively few fleet vehicles running on hydrogen, mainly limited to a few small bus fleets and some private vehicles. For widespread use, these vehicles may require a completely new hydrogen supply and distribution system and it is the issues associated with such a system, referred to in this work as pathways, which are the focus of this research. The chapters in this thesis are structured as follows:-

- Chapter 1. Introduction - This considers the reasons why a change to hydrogen for ground transport may be desirable and what factors may cause this change. It explores why hydrogen may be a realistic option, some background on hydrogen and what obstacles there may be to developing a hydrogen economy.
- Chapter 2. The alternatives – A review of alternative vehicles and fuel technologies. In effect, a review of the competition to any future hydrogen ground transport system.
- Chapter 3. Hydrogen technology – A review of the current state of production and distribution technology relating to hydrogen as a potential “fuel” for fleet vehicles.
- Chapter 4. Relevant hydrogen research – A review of current hydrogen research, focusing mainly on the issues surrounding the supply and distribution of hydrogen.
- Chapter 5. Case studies – A review of recent demonstration projects. In particular, the CUTE bus project and its particular relevance to this aims of this research. This chapter also reviews the United States DoE modelling techniques for potential hydrogen production and distribution systems.
- Chapter 6. The choice of research – This chapter brings together the conclusions from chapters 1 to 4 to identify and define the research question. It will outline the approach to modelling in general and define the key areas that need to be modelled, to address some of the questions raised in earlier chapters.
- Chapter 7. Modelling and data gathering – This chapter introduces the model developed for this thesis and explains how it works in detail. This will include an explanation of

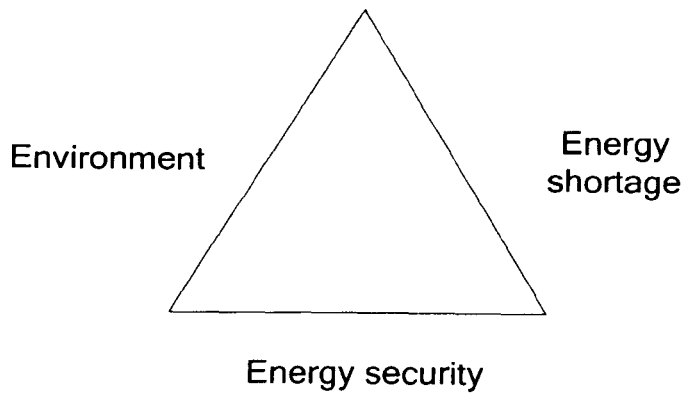
the modelling techniques used, including an overview of data sources and where assumptions and estimations needed to be made.

- Chapter 8. Modelling results – This chapter reports on the results of modelling a number of different scenarios, such as fleet sizes, supply chain lengths as well as changes to energy costs etc.
- Chapter 9. Technology and other developments – From the results in chapter 8, some potential improvements in the supply and distribution system will be modelled in an attempt to reduce cost and emissions and so improve the case for hydrogen.
- Chapter 10. Summary – This chapter will include conclusions from the model results, recommendations for improvements, some suggestions for future work and a brief review of professional and personal development during this period of learning and research.

As a starting point, before this research can consider hydrogen as an energy source for vehicles, it is appropriate to consider why a change is desirable and what might be the forces behind any change. It is also appropriate to consider what the current options are, and why hydrogen may currently be the most viable, if not the only long-term option. The rest of this introductory chapter provides some background on hydrogen and what obstacles may need to be overcome.

## **1.1 Reasons for change**

Depending on perspective, there appear to be three main reasons for change in vehicle fuel systems, which are summarised in Figure 1-1 below. It considers three primary reasons for change, environmental issues, energy security (also referred to security of supply) and energy shortage. It does not consider economics (cost) as a reason for change at this stage, but cost is used throughout this research as measure to evaluate the options for change to a hydrogen economy. One other reason for change which is not included in the diagram is energy efficiency. Hydrogen, like electricity, is an energy carrier. This means that they both have to go through conversion processes before they end up as hydrogen or electricity, these processes have varying degrees of efficiency, but none are 100% efficient. It is usually more efficient to use the feedstock used to make the hydrogen or electricity directly, if possible. All of these issues will be explained and addressed later in this section.



Environment	Energy shortages	Energy security
<ul style="list-style-type: none"> <li>• Reduction in greenhouse gases (CO<sub>2</sub>, NOx<sup>1</sup>)</li> <li>• Eco friendly use of waste products.</li> <li>• Desire to use renewable energy.</li> <li>• Desire to meet emissions goals</li> </ul>	<ul style="list-style-type: none"> <li>• Oil reserves are not increasing and perhaps future supplies may be difficult to access.</li> <li>• Hydrocarbon gas supplies a long way from point of use.</li> <li>• Emergence of rapidly developing economies greatly increasing World's energy requirement.</li> <li>• An alternative long term energy solution to oil and gas.</li> </ul>	<ul style="list-style-type: none"> <li>• Minimising reliance on Imported energy.</li> <li>• Changing political climate increases dependence on politically unstable regimes.</li> <li>• Hydrogen can be produced from multiple sources of feedstock and is not dependent on solely hydrocarbons.</li> </ul>

**Figure 1-1 Reasons for change in vehicle fuel systems**

Most advocates of a hydrogen economy seem to justify the potential change from one or more of these positions, some of which are linked. Perhaps the most widely discussed reason for change relates to environmental issues associated with the burning of hydrocarbon fuels. The issue is usually discussed in terms of global warming. One typical view is that:-

*"Fossil fuel combustion generates very large quantities of carbon dioxide, the most important anthropogenic (human induced) greenhouse gas. The majority of the world's scientists now believe that anthropogenic greenhouse gas emissions are causing the earth's temperature to increase at a rate unprecedented since the ending of the last ice age" (Boyle G et al., 2003).*

The key factor here is the timescale comparison with the last ice age. Climate change is an emotive topic in current affairs, but the weight of scientific opinion supports the view that warming of the climate system is a reality. This was emphasised in a speech by Dr. Rajendra Pachauri at the welcoming ceremony at the recent 2009 climate conference in Copenhagen, with the statement that:-

*"One of the most significant findings of the AR4 was conveyed by two simple but profound statements: Warming of the climate system is unequivocal as is now evident from observations of*

<sup>1</sup> NOx is a generic term for Nitrogen oxides, which include Nitric oxide – NO, Nitrogen dioxide – NO<sub>2</sub> and Nitrous oxide – N<sub>2</sub>O, of which NO and NO<sub>2</sub> are products of combustion in internal combustion engines



*increases in global average air and ocean temperatures, widespread melting of snow and ice and rising global sea level"; and "most of the observed increase in temperatures since the mid-20th century is very likely due to the observed increase in anthropogenic GHG concentrations. In the twentieth century average global temperature increased by 0.74 degrees C."* (Pachauri R, 2009).

It appears that the scientific consensus is that global warming exists, and that the balance of probability is that burning of hydrocarbons contributes to this problem. Consequently it is appropriate to consider environmental issues as an important reason for change to hydrogen which could be produced with little by way of carbon emissions.

The issue of energy shortage has been a topic for many years now, varying in emphasis over time. However, we are possibly entering a time when this could become an increasingly important factor in driving the search for new fuels. One key marker of oil reserves is the oil reserves to production ratio which fluctuate according to demand and the amount of new oil discovered. According to BP, the ratio of world oil reserves to production have remained largely static between 1988 and 2004, at 40 years of reserves (BP, 2005). So it would appear that there is no imminent shortage of oil, as new discoveries are approximately matching demand. But this is only part of the issue, as not all oil is readily accessible and the oil which is cheapest to extract has been used first. Lord Oxburgh (former chairman of Shell) succinctly summed up the issue in a report when he stated that *"There isn't any shortage of oil, but a real shortage of cheap oil that for too long we have taken for granted"* (ITPOES, 2008).

. An example of energy security can be found in North America, which still has reserves of hydrocarbons (oil, gas and coal) but has an increasing reliance on imported energy. In 2007 the USA passed the Energy Independence and Security Act (Govtrack.US, 2009) with the stated aim - to pass *"an act to move the United States toward greater energy independence and security, to increase the production of clean renewable fuels, to protect consumers, to increase the efficiency of products, buildings, and vehicles, to promote research on and deploy greenhouse gas capture and storage options, and to improve the energy performance of the Federal Government, and for other purposes."* This policy is based on energy security, due to a desire not to be over reliant on hydrocarbon fuels from politically unstable regions.

Iceland is one example that does not quite fall within the category of energy shortage or security. It has virtually no reserves of hydrocarbons, but significant amounts of natural geothermal energy. Although it has made good use of its natural resources where possible, Iceland has had to rely on

imports for transport fuels. Almost 70% of Icelandic electricity is produced from renewable sources such as geothermal or hydro power, but this still leaves 30% reliance on hydrocarbon imports (Maack M and Skulason J, 2006). Iceland's aims appear to be initially driven by a shortage of hydrocarbon energy, even though it has a significant amount of geothermal energy. One could argue that it is easier to convert and use it's abundance of natural energy into electricity. Both hydrogen and electricity are energy carriers and possibly competitors in the race for alternative energy. However they both have advantages and disadvantages when comparing methods of storing and distribution. This is an issue which will be addressed later in this research.

Hydrogen has been advocated as an alternative to current fuels , such as petrol and diesel used for transport (Balat H and Kirtay E, 2010), and sometimes quoted as "near zero emissions" at the point of use (Verhelst S and Wallner T, 2009) . This can be seen in the vehicle emission specification of the CUTE buses, which are examined in detail later in this thesis (CUTE, 2006, p57). It is the term "point of use" which is key to this statement. As will be demonstrated later in this thesis, hydrogen can actually emit more carbon dioxide than conventional fuels if the whole life cycle of production, distribution and use of the fuels are considered.

Even though there has been a significant increase in interest in the use of hydrogen since the start of this research, it is acknowledged that it is not a short term fix and is not necessarily the panacea for reduction in carbon dioxide emissions from transport. In an article *"The hype about hydrogen"* Romm warns about this when he says *"if we fail to limit greenhouse gas emissions over the next decade, and especially if we fail to do so because we have bought into the hype about hydrogen's near term prospects we may be making an unforgivable national blunder that may lock in global warming for the United States of 1° F per decade by mid-century"* (Romm J J, 2004, p 74).

The cost of hydrogen can vary significantly as this research will show, yet it is unlikely to be a driver for change in the near term. At the start of this research in 2002, oil was approximately \$25 per barrel. In May 2008 it reached \$130 per barrel with the corresponding price for diesel at £1.30 per litre. Yet at no point was hydrogen cost competitive with diesel even at £1.30 per litre, as this research will show later. In 2008, Goldman Sachs oil analysts predicted oil to reach \$200 per barrel (Gelsi S, 2008), and perhaps hydrogen may be economically viable at that price level. However the volatility of oil prices would make it difficult to justify a change for economic reasons alone. In any case, long term high oil prices are most likely to come from sustained periods of demand

outstripping supply, which one could argue is based on energy shortage rather than economic grounds.

Although energy efficiency is an unlikely reason for change, there are circumstances when conversion is desirable. For example, converting natural gas to electricity for lighting as electrical lighting is far more effective than gas lighting. Generally, it makes more sense from an energy point of view to use the hydrocarbons directly. Evidence of this can be seen later in this research when modelling hydrogen pathways. For example, 1kg of hydrogen contains 120 MJ of energy. If this hydrogen was produced using Steam Methane Reforming of natural gas, approximately 160MJ of natural gas energy would be required to produce one kg of hydrogen. If used in an internal combustion engine, it could be more efficient to use the natural gas directly rather than convert it to hydrogen and then use it in an internal combustion engine. This type of energy balance will always apply when using energy carriers.

This does not necessarily mean hydrogen should be excluded on energy efficiency grounds alone. For example, solar energy may be used to generate electricity and / or hydrogen. The process may be "energy inefficient", but if the energy source (the sun) is considered limitless and is not used for any other purpose, then efficiency may be a lesser concern.

The title of this thesis refers to economic and environmental considerations and yet economic considerations appear to have been rejected already. Whilst cost alone may not be a reason for change, it cannot be ignored when considering options based on the chosen reasons for change. To a similar extent, environmental issues alone may not be the prime driver for change but again pathways need to be measured against environmental impact. It is unlikely that any acceptable new alternative fuel for a transportation system would be significantly more expensive and less environmentally friendly than the current hydrocarbon-based system we have today.

## **1.2 What is hydrogen**

Before progressing further, it is worthwhile considering the basic nature of hydrogen, its uses and why it has emerged as the seemingly ideal solution to all our fuel requirements for vehicles in the 21<sup>st</sup> century. Hydrogen is plentiful, as it is the world's most abundant element, however it does not exist naturally in a useful form. It is a very flexible energy carrier / fuel, because of the many different ways that hydrogen can be produced, converted and used. It makes the definition of hydrogen as an energy carrier particularly appropriate.

Hydrogen is a gas at ambient temperatures and atmospheric pressure, It is colourless, odourless and non toxic and non carcinogenic. It is a highly reactive element, combining readily with carbon or oxygen, as well as other elements. Unlike other fuels it does not need to be mined. Consequently it can be produced wherever there is a source of hydrogen atoms. The two most common ways of extracting hydrogen is from hydrocarbon fluids in the form of  $C_nH_{2n}$  , (where n = the number of atoms, eg: methane =  $CH_4$ , etc.) and water  $H_2O$ . In 2005, these two processes accounted for nearly all hydrogen produced, at 96% and 3.9% respectively (Lemus RG and Martínez Duart JM, 2010).

One of the key properties of hydrogen is that it is a very light gas with a molecular weight of 2.02 grams/mole and a relative density compared with air of 0.07. This presents two practical problems with hydrogen systems. Firstly, having a low density makes it difficult to store large amounts in gaseous state without large storage systems. Secondly the gas is particularly prone to leakage from storage systems either through joints or at the molecular level, permeating through pipe work and storage vessels under certain conditions (e.g.: extremely high pressure). It is flammable over a much wider range of concentrations compared with other fuels and it burns with an invisible flame, both of which present additional safety issues compared to a hydrocarbon fuel.

Hydrogen liquefies at  $-253^{\circ}C$  which is at the extreme of cryogenic temperatures. This presents difficulties with both the selection of storage materials and insulation requirements to prevent heat gain to the system and hence losses due to boil off. Hydrogen also requires significant amounts of energy to liquefy. Safety concerns are mainly related to issues associated with handling of cryogenic fluids and the potential release of flammable gas clouds due to boil off of the liquid hydrogen. For further information on the properties of hydrogen refer to Appendix 1. A basic understanding of the properties of hydrogen has been necessary during the modelling phase of this research. Some properties, such as flammability etc. are already understood and addressed in the current hydrocarbon energy system for transport, but there are perhaps three properties of hydrogen that differentiate it from other sources of energy. These are –

- Cryogenic temperature in liquid state
- Relatively low density in gaseous state
- High energy value by mass (MJ/kg) compared with other hydrocarbons.

### 1.3 The history of hydrogen and hydrogen vehicles

Hydrogen as a fuel has been around for a considerable time. First discovered in 1766 when Henry Cavendish recognised a new substance which he named “inflammable air”. later named by Antoine Lavoisier as “hydrogen” in 1783 (Hoffmann P, 2002). In 1898, James Dewar first liquefied hydrogen (Krasae-in S et al., 2010). Another key date in the history of hydrogen as a substance was the Hindenburg air ship which crashed in 1937, bringing hydrogen and its potential danger as a substance into public perception (Boyle G et al., 2003).

The first hydrogen fuel cell was developed by Sir William Grove in 1839, almost 170 years ago (Air-Liquide, 2009), although credit for the first practical hydrogen / air fuel cell is attributed to Francis Bacon in 1959 (The Hydrogen Association, 2009). In 1807 Francois de Rivaz invented an internal combustion engine which ran on a mixture of hydrogen and oxygen (Verhelst S and Wallner T, 2009) . It wasn't until much later (1882) that petrol was used as a fuel when Daimler and Maybach developed an Otto cycle internal combustion engine to run on petrol (Boyle G et al., 2003, p298).

Yet despite this relatively long history as both a fuel and use in vehicles, hydrogen and fuel cells in particular, the uptake of hydrogen vehicles is a fairly recent phenomenon. There are a number of possible factors why hydrogen was not the ultimate choice for fuel for vehicles and why hydrocarbons took over, possibly due to the difficulties of producing, handling and storing hydrogen. Certainly technology has changed in that time, but perhaps the criteria for judging success and failure, such as global climate change, energy shortage and energy security have also changed. It is unlikely that any of these factors were considered two hundred years ago.

### 1.4 Why hydrogen for ground transport

There are many ways in which energy can be provided for ground transport. This variety is not just limited to the primary energy source, but also includes fuel energy storage and method of propulsion. This is identified in Figure 1-2, although two of these “fuels” shown in the diagram are in fact energy carriers. The hydrogen and electricity pathways have been highlighted in the diagram to identify the variety of ways both hydrogen and electricity can be produced. It also shows similarities between the two systems and pathways. This can be shown in the pathway route from renewable electricity to an electric drive, both hydrogen and electricity pathways are in parallel except for the addition of a fuel cell for the hydrogen pathway.

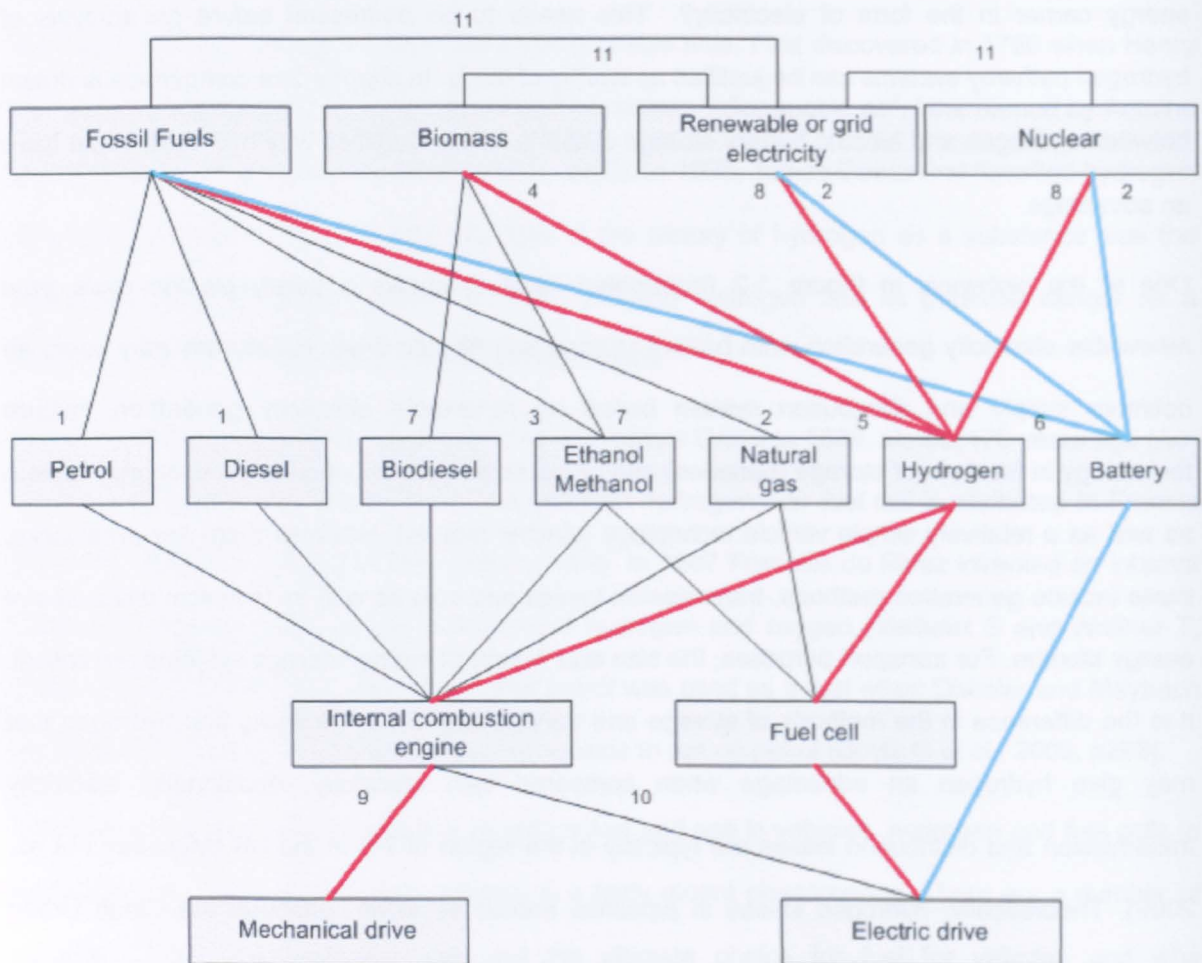
Electricity is an established energy carrier in the UK with mature technologies for generation using coal, gas, oil and nuclear energy, as well as some renewable methods such as wind, hydro, tidal

and wave power. The obvious question is, why use hydrogen when we have a readily available energy carrier in the form of electricity? This needs to be addressed before an analysis of hydrogen pathway systems can be justified as worthy of study. In chapter 2, a comparison is drawn between hydrogen and electric battery storage systems which identifies why hydrogen could have an advantage.

One of the pathways in Figure 1-2 (highlighted in blue) shows a purely electric route from renewable electricity generation, with battery storage and electric drive. Initially this may seem an optimum supply and distribution system based on renewable electricity generation, mature technology in the form of storage (batteries) and an established distribution (electricity grid) system as well as a relatively simple vehicle technology (electric motors). However there are drawbacks, these include generation methods, transmission losses and cost as well as technical difficulties of energy storage. For transport purposes, the size and weight of energy storage systems are critical. It is the difference in the methods of storage and transporting of the electricity and hydrogen that may give hydrogen an advantage when compared with electricity. Additionally, electricity transmission and distribution losses are typically in the region of 7% in the UK (MacLeay I et al., 2009). Theoretically, hydrogen losses in pipelines should be lower, although the Clean Urban Transport for Europe (CUTE) project reported high losses. The CUTE hydrogen losses will be discussed further in chapter 5.

Unlike other hydrocarbon sources of energy for transport, which are largely dependent on oil and its derivatives, hydrogen can be produced from many sources, and this flexibility could be an important advantage. It also has the potential to be used in both mechanical and electric drive units which gives it a further advantage in terms of flexibility over electricity as an energy carrier. The hydrogen options are highlighted in red in Figure 1-2.

## Primary Energy / Fuel Energy storage / vehicle alternatives



- [1] Refining [2] Direct [3] Gasification and Synthesis [4] Gasification only  
 [5] Reforming or gen elec / electrolysis [6] Elec. Generation [7] Fermentation  
 [8] Electrolysis [9] Mechanical transmission [10] On board generator [11] Grid and renewable electricity is generated from a variety of sources.

**Figure 1-2 Energy pathways to vehicles**

Diagram amended from (Lane, 2002, page 52)

(Hydrogen pathways are identified in red, Electricity pathways are identified in blue)

A limitation of the pathway diagram shown in Figure 1-2 is that it does not identify where the energy is produced / stored / converted. Hydrocarbons (fossil fuels) are generally processed at large scale processing facilities. Hydrogen and electricity can be produced at a variety of locations. Centralised production can be achieved via pathways 5 & 6, but it would equally be possible to produce hydrogen or electricity in local (neighbourhood) facilities from either renewable grid electricity, renewable generated electricity generated on site, or natural gas if a pipeline were available.

One potential benefit that hydrogen has compared to electricity is the flexibility of ways that it can be stored and transported. It can be stored in gaseous, liquid and (potentially) in solid state; it can be transported by either road or rail in tankers, as well as pipelines. However, despite this flexibility,



hydrogen faces a number of obstacles due to its physical properties compared with other fuels such as diesel, which might make the choice of any distribution system more critical. The wide range of options certainly complicates the issue of which is the optimum method of distribution and storage.

### 1.5 The obstacles to a hydrogen economy

This section provides a brief review of issues associated with hydrogen production distribution and end use. This is to aid the reader in understanding some of the problems associated with any potential change to hydrogen as a fuel for transportation. It is intended give an overview only. The issues will be addressed in more detail in chapters two to four of this thesis.

Hydrogen probably has the most production options of all current fuels / energy carriers, the two most common methods being Steam Methane Reforming (SMR) of natural gas, and electrolysis. There are also future novel technologies being developed which could replace the existing technologies in time. Consequently production techniques can evolve over time as more efficient / cost effective / environmentally friendly technologies are developed. The problem is not so much related to how hydrogen is produced, but where it is produced and hence the scale in which it is produced.

One issue is whether to produce the hydrogen in large scale centralised production plants or small scale localised systems. If large scale centralised distribution systems are preferable, then a delivery system will be required for the hydrogen. In the case of hydrogen this can be in either liquid or gaseous state with current technology. Currently nearly all hydrogen is produced and used in gaseous state for transport applications. Liquefaction of hydrogen is not necessary unless it is required to be stored on board vehicles in liquid state. This is because liquefaction of hydrogen adds an additional step in the process, which has both cost and environmental impacts. But as hydrogen has a very low density and hence low energy value by volume in gaseous state, it is possible that it could be cheaper to transport hydrogen in liquid state.

Key characteristics of transporting gaseous and liquid hydrogen are shown in Table 1-1, in which it is compared to petrol. The data in this table highlights the significant increase in road tanker journeys required to carry hydrogen to a filling stations compared with a typical hydrocarbon fuel such as petrol. To provide a valid comparison, the right hand column shows how far a car can be driven on one road tanker full of the three fuels, delivered to the filling station.



Hydrogen tanker storage capacities can vary significantly. Gaseous hydrogen trailers can vary between 63 and 460kg, whilst typical liquid hydrogen capacities are between 3,600 to 4,300 kg. Values used are typical (Amos W, 1998, p32,33).

Fuel	Typical road tanker capacity (kg)	Storage pressure (Bar g)	Volumetric Capacity (m3)	Energy per tanker
Gaseous hydrogen	360	220	25	43 GJ
Liquid hydrogen	3,500	2	50	420 GJ
Petrol	19,500	2	26	877 GJ

Table 1-1 Energy carrying capacity of various tankers

The purpose of this diagram is to compare the energy carrying capacities of various types of tankers, hence the comparison with only one vehicle technology. It is recognised that the additional efficiencies of fuel cell vehicles would reduced the number of hydrogen tanker journeys, and this will be taken into account in modelling work later in this thesis.

The cost of distribution for centrally produced hydrogen is dependent on the distance from the point of production to the point of loading on board vehicles (supply chain length). Whilst this may be a relatively small cost variation when delivering hydrocarbon fuels such as petrol or diesel, the additional tanker journeys required for hydrogen could add significantly to distribution costs by road.

With the possibility of hydrogen being transported in liquid state at cryogenic temperatures and gaseous state at high pressures, it is already clear that it will not be possible to adapt the existing distribution systems for petrol and diesel to carry hydrogen. In addition, the two hydrogen systems are incompatible, requiring different types of tanker. We also need to consider the possibility of storing hydrogen in solid state in the future, and transportation by pipelines, so a number of pathways are already beginning to be identified. New distribution systems would have a significant cost and at present, it is not clear how these would develop and who would pay for them.

It is a “chicken and egg” situation; whether to produce the vehicles first (chicken) and then develop the distribution system (egg) to meet demand or vice versa. At present it is not even clear which is the best “chicken” and even if it proves to be hydrogen there are number of “egg” options to consider. A significant amount of research may still required to identify the best option. There may be no one single solution to fit all variations of demand and supply chain length.

Whilst the Internal Combustion Engine (ICE) appears to have won the original race for supremacy, when compared with Sir William Grove’s fuel cell, circumstances may be significantly different in

the current era. It appears that the original inefficiencies of the ICE were sidelined in the race for a unit to power vehicles. In the current climate it is possible that a Fuel cell vehicle will eventually supersede an ICE as it is almost twice as efficient when considering fuel to wheel (see later comments in section 2.4).

## **1.6 Hydrogen issues relevant to this research**

The questions associated with hydrogen that have been raised in this introduction can perhaps be summarised as follow:-

1. Why should we change transport fuels and why hydrogen?
2. If hydrogen, how should we produce it and where?
3. What type of distribution system would be needed for hydrogen and how would it compare with the current hydrocarbon model for production and distribution?
4. What are the challenges to technologists and researchers?

These issues are wide ranging and cannot all be considered in sufficient detail as a single research topic. This research does not consider in detail why a change is necessary or desirable, but it is taken that the reasons for change will require a careful consideration of cost (Economic) and emissions (Environment) issues. This research does however need to review any existing hydrogen distribution systems and its use within the UK, although the hydrogen requirements for future transport needs would be significantly above current usage.

This research has considered the issue of 'why hydrogen', in this chapter. What the alternatives are, will be addressed in chapter 2, in particular, the similarities and differences between hydrogen powered vehicles and electric battery powered vehicles as they share similar technologies in terms of the method of propulsion. The main difference between these two technologies is the method by which energy is stored on board. However, this research does not seek to justify hydrogen as the best or indeed only solution for an alternative fuel for vehicles, but it does provide evidence that could contribute towards a discussion on this issue.

This research does not address issues related to hydrogen production, but production methods are likely to significantly affect the overall pathway cost and emissions. Current and future technology and research will be reviewed in chapters 3 and 4, but will be limited to the relevant aspects of this research, i.e. cost and emissions of the various processes rather than the technical issues associated with production / storage and distribution.

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## 1.7 The aims and boundaries of this research

If hydrogen has a role to play in providing energy for ground transport, it suffers from one major disadvantage compared to its competitors. Any hydrogen required for transportation purpose would be over and above the current industrial gas market, requiring a significant expansion of the existing supply and distribution system. Any additional supply and distribution system is likely to be expensive and currently there are a number of pathway options available which may be mutually exclusive, ie: it will not be easy to interchange from one to another. If these potential pathways can be evaluated to reduce the number of options by eliminating pathways likely to be uncompetitive on either economic or environmental grounds, it may be possible to take a more focused approach to future technology developments.

What this research does seek to do is to establish that the supply and distribution system is potentially an obstacle to a future hydrogen economy. Not only because of the challenges associated with hydrogen distribution, but each different method of transporting hydrogen required a different distribution system and infrastructure. Unfortunately, the supply and distribution cannot be studied in isolation, as the best solution may be to have no system at all and to rely on producing locally at the point of loading on board vehicles. Consequently, both centralised and localised production will need to be addressed in this research.

This research will focus on fleet vehicles, which in this context means vehicles that start and finish their working day at the same point. The full reason for this choice is explained in Chapter 6 with buses specifically used, although this research could perhaps apply equally to taxis and short range delivery vehicles such as supermarket home deliveries vehicles. The key point about this type of vehicle is that they only require one fuelling point and hence only a simplified distribution network needs consideration. A single point distribution will simplify the modelling of the numerous pathways that are possible with hydrogen.

It is a little more difficult to establish the system boundaries for the study of the end use of hydrogen on board vehicles. Ideally it would include the whole life cycle of vehicles from cost of manufacture, operation, maintenance to disposal. This would present some difficulties, firstly because the only costs available are for research and development demonstration vehicles as used in projects like CUTE, where unrealistic maintenance regimes were used. This would disadvantage Fuel Cell vehicles (FCVs) due to cost. Conversely, it would disadvantage FCVs if the additional efficiencies achievable were not taken into account. So the system boundary drawn will

take into account the additional efficiency without consideration for the actual cost. It is justifiable in this research topic as it is concerned primarily with the energy delivery system.

In concluding this introduction on hydrogen it is worthwhile stating the original hypothesis of this research and its aims. The hypothesis of this thesis is that whilst hydrogen may be an option as a fuel for future ground transport systems, it is the lack of a supply and distribution system which is likely to prevent such a hydrogen economy developing rather than the production of hydrogen or the vehicle technology required. Whilst hydrogen production and its end use in vehicles has been reasonably well researched and tested, the supply and distribution systems have lagged behind in terms of both research and technology developments.

The aim of this research is to identify the key characteristics of a hydrogen delivery system and consider the various methods of delivery. This will be done by reviewing the many hydrogen pathway options, reducing the number of these options by analysis and quantifying each pathway in terms of both cost and emissions.

Once this has been achieved, they can be measured against a base diesel reference case to identify how competitive each pathway is with diesel in terms of both cost and emissions reduction potential. If hydrogen is not cost competitive, this research will consider methods of reduction in both cost and emissions, and also identify the price that diesel will be required to reach to make hydrogen price competitive as a system.

It is also hoped that the analysis will reduce the number of potentially viable pathways to simplify the choices of future hydrogen supply and delivery systems. By reducing the possible number of pathways and modelling the remainder, it is intended to identify a decision making process to determine the most effective hydrogen supply and distribution systems for future ground transport applications.

## **CHAPTER 2    ALTERNATIVE VEHICLES AND FUELS**

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This chapter reviews some of the current options available to change or improve current vehicle fuels. To consider these options, it is important to review the vehicle as well as the fuel and supply distribution system from a cost and environmental perspective. Although this research has a focus on fleet vehicles, the issues surrounding costs and emissions of engine technology are the same for private vehicles. Fuel and supply distribution systems are similar but fleet vehicles do not need the wide distribution networks necessary for private vehicles.

This review covers emerging and potential technologies, but excludes dual fuel vehicles such as those using Compressed Natural Gas (CNG) or Liquefied Petroleum Gas (LPG), because both of these types of vehicles use the same vehicle technology (Internal Combustion Engines) and a similar distribution system.

### **2.1    Hybrid vehicles**

Hybrid vehicles have been available since 1997 when Toyota launched their Prius model in Japan (Warren J (Ed), 2007, p 55). Although Toyota were the pioneers of this technology, other manufacturers are now starting to market hybrid vehicles, and it is currently perceived as a “green” car.

Hybrid electric vehicles rely on a combination of a mechanical drive system, powered by an Internal Combustion Engine (ICE), and an electric motor. They can be designed in a number of different formats, such as parallel, series or a combination of both. In parallel systems, both the ICE and the electric motor drive the wheels. In series systems the ICE is used to generate electricity which drives the wheels through the electric motor, and the combination format uses a mixture of both depending on demand. Both the parallel and combination formats require complicated transmission technology, whilst the series format uses the ICE merely as an electricity generator, with energy losses in the conversion process.

The main benefit of hybrid vehicles with respect to fuel supply and distribution systems is that no change is needed. The only fuel that the vehicles take on board would be either petrol or diesel, as electricity used is generated on board. With future plug in hybrids having the facility for external charging of the batteries, there is a ready made supply and distribution system in the form of the national electricity grid, although there may be a requirement to upgrade the carrying capacity of the grid if there was a significant uptake of this type of vehicle.

Hybrid vehicles have advantages in terms of fuel economy and emissions, but at the expense of cost as Table 2-1 in section 2.6 shows. The extra cost (about 15%) is due to the additional complications of the transmission systems and associated hardware. It is difficult to envisage hybrid vehicles ever matching conventional vehicle purchasing costs, although the price differential is offset by savings in fuel consumption.

As hybrid vehicles still use hydrocarbon based fuels, they can only reduce CO<sub>2</sub> emissions by reducing fuel consumption, and this alone is unlikely to meet typical current targets for CO<sub>2</sub> emissions reduction, such as the Royal Commissions recommendations to cut CO<sub>2</sub> emissions by 40% by the year 2020 (Warren J (Ed), 2007, p16). They offer the potential for a short term reduction in emissions with minimal additional costs, but they will not resolve other long term issues of energy shortage or energy security. Also, it does not significantly reduce the emissions generated in the production and distribution of the fuel (apart from reducing demand).

## **2.2 Efficient diesel engines**

Diesel engines operate on what is known as the diesel cycle and were developed by Rudolph Diesel in 1892. They offered better efficiency when compared with a conventional four stroke petrol engine (Otto cycle), also developed at around the same time. The Diesel efficiency of 26% was a significant improvement when compared with 15% for the Otto cycle (Boyle G et al., 2003). Although both engines have been developed significantly since, diesel engines still enjoy a significant advantage over comparable petrol engines in terms of fuel economy.

Although diesel engines have been powering vehicles for more than a hundred years, the “alternative” element is that there have been many significant improvements in the technology and these are still continuing. Diesel engines have continued to develop since the original was developed more than a hundred years ago. The addition of turbo chargers has improved performance. New filtration systems, such as particulate filters and catalytic converters have reduced emissions. The improvements in emissions were significant enough to exclude some diesels from the London congestion charge in 2008 (although this has subsequently been rescinded). It would appear that motor manufacturers’ recent attempts to produce “green” vehicles have been split between hybrids (eg: Toyota Prius) and diesels (eg: Volkswagen Polo Blue motion) at present.

Diesel vehicles have advantages in terms of fuel economy and emissions but are slightly more expensive than petrol equivalents. Unlike hybrids, the diesel powered vehicle uses much of the

technology found on conventional petrol engines, so the cost differential is less. The most common method of comparing vehicle emissions between vehicles is to measure the CO<sub>2</sub> produced at the exhaust pipe. Diesel engines generally produce less CO<sub>2</sub> than petrol, however they tend to produce more oxides of nitrogen (or NO<sub>x</sub> as it is known), which is also a greenhouse gas.

One could argue that if all private vehicles were diesel powered, a significant improvement in vehicles emissions could be achieved. This is already happening in Europe. In 1983 only 16% of vehicles were powered by diesel engines, by 2006 this figure had increased to 50% (Warren J (Ed), 2007). However fleet vehicles such as buses and lorries have already made the transition, with nearly all fleet vehicles powered by diesel fuel. It is reasonable to conclude that the benefits of emissions reduction have already been achieved with respect to fleet vehicles. As with hybrid vehicles, no change to the existing fuel and distribution systems is required and hence no need for further discussion with respect to this research project.

## **2.3 Bio-fuel powered vehicles**

There is a lot of debate about the benefit of biomass as a fuel. The following definition is taken from an article in the Engineering and Technology Journal (James A, 2010):-

*"The basic feedstock for first generation bio-fuels, are products that would normally enter the animal or human food chain. Second generation bio-fuels can be defined as feedstock outside the food chain, which could include the waste products from food production (eg: wheat stalks) or crops grown only for special energy crops which have no food value (eg: Miscanthus). Third generation bio-fuels are likely to be algae based".*

The subject of biomass as a fuel in general, and for vehicles in particular, is quite wide ranging. As such, detailed analysis is outside the scope of this research project. For further reading on this subject, the author recommends a report by the Royal Commission on Biomass as a renewable energy source. (RCEP, 2004)

Bio-fuel vehicles are powered using conventional ICEs so very little new technology is required, apart from perhaps some minor developments for differences in fuel combustion. The main technology developments appear to be associated with the production of the bio-fuel itself. Some processes such as the production of ethanol from grain are fully developed but there are a wide variety of technologies and according to the National Research Council *"Lower cost bio-fuel production methods and conversion processes will have to be developed for large scale*

*commercialisation*" (Ramage M et al., 2008, p62). This implies that production technology developments are still required.

The cost of bio-fuels and bio-diesel in particular, vary significantly due to feed stock costs with typical prices in the region of \$3.00 per gallon (Ramage M et al., 2008, p57) based on soybean oil. During the same period, wholesale diesel was approximately \$1.80 per gallon. Although bio-diesel is more expensive, it has another potential obstacle. It is not clear that sufficient fuel can be produced to meet the demand without affecting other issues such as the need for land to grow food crops. This issue was raised as a by Gurgel in his paper on the implication of land use in the bio-fuels industry (Gurgel A et al., 2007). Several questions were raised, one of which relates to the competition for land if crops are grown that have food use (such as Maize). It is claimed that this will lead to competition between the food and energy sectors, which could affect food prices.

Palm oil is one such multi purpose crop which may be suitable as a feedstock for biomass, without actually requiring land specifically for feedstock to be grown on. Cooking oil is the primary product from the crop but a significant amount of the remainder of the crop can be used for biomass. For example, the fresh fruit bunch is used for the palm oil (21% of the plant), while the rest, 6–7% palm kernel, 14–15% fibre, 6–7% shell and 23% empty fruit bunch (EFB) are left as biomass (Kelly-Yong T L et al., 2007).

There is some environmental benefit in using bio-diesel compared with conventional diesel, but again varies significantly depending on feedstock. For example, using well to wheel CO<sub>2</sub> emissions analysis a typical conventional diesel vehicle produces 130 gCO<sub>2</sub>/km, compared with 131 and 15 gCO<sub>2</sub>/km for ethanol from corn and cellulose respectively (Ramage M et al., 2008, table 4.4, p 60). The source of bio-fuel is crucial as some crops are energy intensive to produce. Bio-fuels from the right sources can cut CO<sub>2</sub> significantly, but these are largely second and third generation bio-fuels. In some cases adding increased concentrations of soybean to a diesel (between 3 to 20%) can actually increase CO<sub>2</sub> emissions on a g/km basis, although the addition of Ethanol (between 2 to 5%) can reduce emissions. (Randazzo M and Sodré J, 2010)

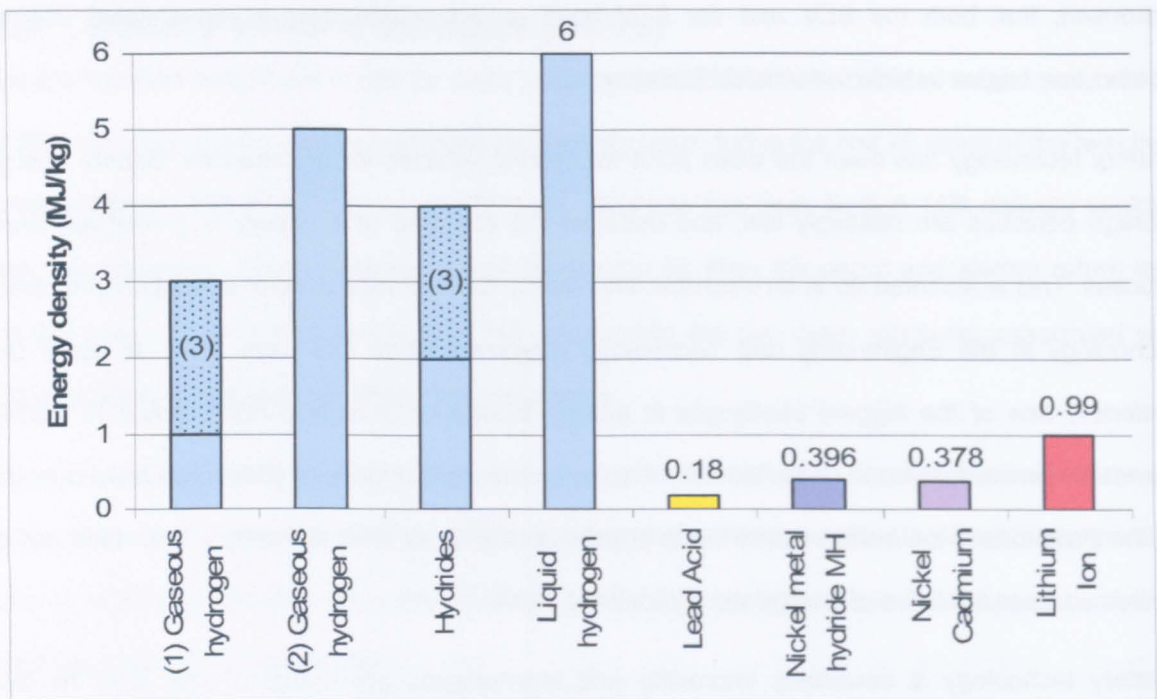
The requirements for a fuel supply and distribution system are again very similar to the current hydrocarbon distribution system, and consequently no further discussion is required here



Sorensen, that both the BEV and the FCV have an advantage over a conventional internal combustion engine vehicle in terms of efficiency. -

Battery technology has been the weak point for electric vehicles for two reasons. Battery energy storage densities are relatively low, and because the charging of a battery is a relatively slow process. This is summed up in an interview with Nancy Gioia, Ford's director of sustained mobility technology in the Engineering and Technology magazine when she says *"It is all about the batteries, one of the biggest challenges is energy storage in a battery cell"* (James A. 2009). However she does go on to claim *"whether it is the nickel metal hydride or lithium, we have now got to the point based on testing where we are quite confident on their durability"*. This does not of course address the issue of energy storage density.

Battery technology is constantly improving and technologists are trying to overcome the two obstacles of energy storage density and charging rates. One relatively new technology using Lithium titanate oxide batteries claim to reduce re-charging times to less than 10 minutes with a range of 150 to 200 miles (Pool R, 2008). Although such charging rates are likely to be beyond the capacity of domestic power supply systems due to the high power transfer rate required. Although perhaps not a significant increase in electricity generation capacity if most charging was carried during periods of low demand (ie at night) If this technology can be produced economically, it is a possibility that electricity may beat hydrogen as the energy carrier of the future for at least some alternative vehicles.. However electricity still lacks behind hydrogen in energy density as Figure 2-1 shows. Four different types of battery technologies (to the right) are compared with three different methods of storing hydrogen (to the left). It shows hydrogen to have a clear advantage over battery, in terms of storage density by mass. However this does not consider total volume of storage, which was identified as a potential obstacle for hydrogen in chapter 1. Hydrogen energy storage densities will be discussed in more detail in chapters 3 and 4. Battery energy densities were taken from a typical battery supplier's website (Nexergy, 2009).



**Figure 2-1 Typical energy storage system densities of hydrogen and electric batteries**  
 (Hydrogen data sources (Eberle U et al., 2006), Battery data sources (Nexergy, 2009))

- (1) Gaseous hydrogen in steel containers
- (2) Gaseous hydrogen in composite containers at 700MPa
- (3) Dotted zone represents a typical range of energy densities

As electricity is the only energy source required for electric vehicles, a supply system already exists in the National Grid in the UK. However, whether sufficient generating or transmission capacity exists is a potential issue. Mackay estimates that if all cars in the UK were powered by electricity, the average power required would be approximately between 40 and 50 GW (MacKay D, 2009). It is dependent on the uptake of vehicles and the charging requirements. A study in California concluded that if 1% of vehicle miles travelled were by BEVs, it would add between 0.1 & 0.3% to electricity demand (McCarthy R and Yang C, 2010). Whilst these figures cannot be directly translated to the UK, it does show that even a relatively small uptake of BEVs would increase demand on both generation and transmission within the UK. The extent of this impact would also depend charging times ie: peak or off peak.

Due to their simplicity, electric powered vehicles (excluding batteries) are likely to be reasonably cost efficient. Early battery powered electric vehicles used standard lead acid batteries, which although relatively cheap have poor energy storage densities. Newer technologies such as Lithium Iron are significantly better but at increased cost. The three main obstacles to BEVs can be summarised as:-

- Battery cost – Batteries can double the vehicle capital cost (Warren J (Ed), 2007)
- Battery energy storage density – Refer to Figure 2-1
- Battery charging rates Typically 6 to 8 hours (Warren J (Ed), 2007)

It will be necessary to overcome all these obstacles before there can be a significant uptake of battery electric powered vehicles. Electric vehicles produce no CO<sub>2</sub> at the point of use. If the electricity used is generated from a renewable source such as wind turbines, this could be considered an environmentally friendly option. So it would appear to be a viable alternative environmentally. Even using a typical UK mix of electricity generation, BEVs still produce a relatively low level of CO<sub>2</sub> as shown in Table 2-1 on page 39.

## 2.5 Hydrogen powered vehicles

Vehicles can be powered by hydrogen in two ways. Firstly, in a conventional Internal Combustion Engine (ICE) and secondly using a fuel cell such as a Proton Exchange Membrane (PEM). Most vehicle manufacturers appear to be focusing on using fuel cells in their hydrogen powered vehicles. The term hydrogen powered vehicle is slightly misleading in the case of Fuel Cell vehicles (FCVs), as the vehicles are powered by electric motors in much the same way as battery powered electric vehicles. The main difference is in the energy storage system which is hydrogen as opposed to electricity in batteries.

### 2.5.1 ICE Technology

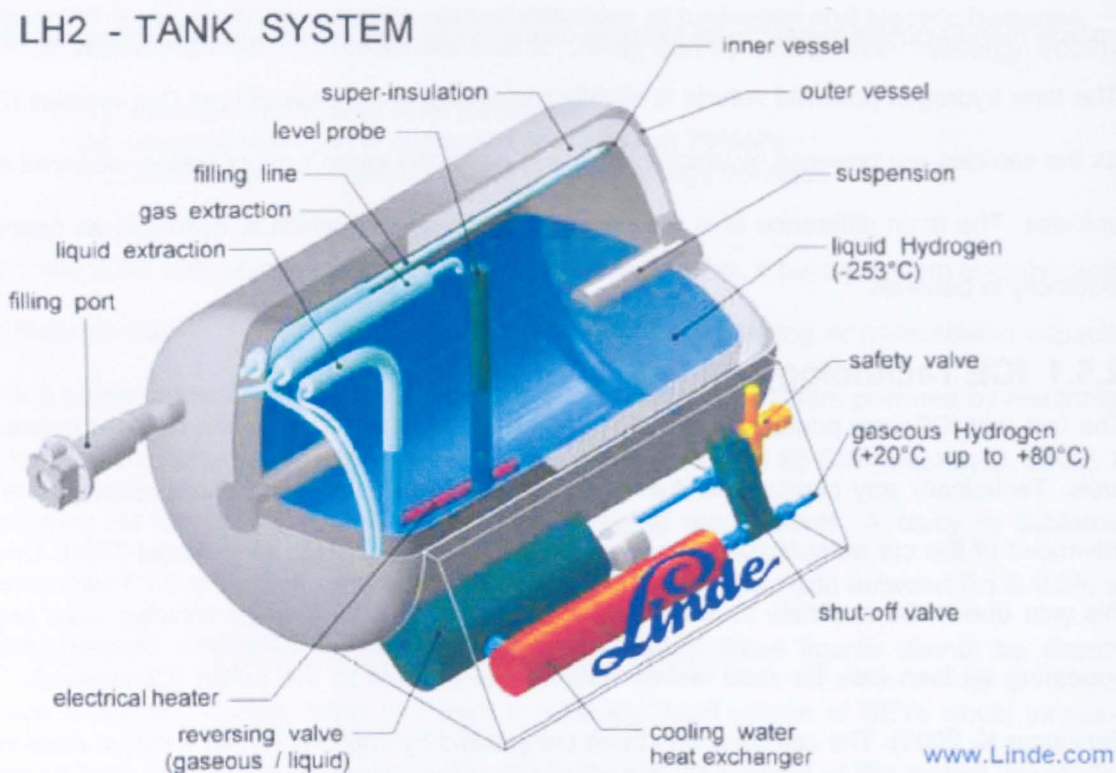
The fact that ICEs are primarily driven by petrol or diesel is due to an abundance of hydrocarbon fuels. Technically any combustible fuel could be used in an ICE. BMW are probably the most advanced of the car manufacturers to use hydrogen in an ICE, with their model 750H. Originally this was due to be available to the public in 2003, but by 2008, these vehicles were only just appearing as loan cars for road testing and not yet on sale to the public (Chmielewski D and Bensinger K, 2008). The company has been using liquid hydrogen (LH<sub>2</sub>) as a fuel in experimental cars since the 1970's, but only in the form of prototypes and concept cars (BMW, 2010). Technically it is a dual fuel vehicle as it has both liquid hydrogen and petrol fuel tanks. Hydrogen is burnt with excess air to reduce the flame temperature in the combustion chamber to below the critical limit above which oxides of nitrogen are formed. As a result it produces practically no emissions in use when running in LH<sub>2</sub> mode.

Even though the car is in limited production, its use is constrained by the relatively few filling stations available (hence the need for dual fuel). The hydrogen tank has a capacity of 8kg and a



range of approximately 200km, whilst the petrol tank capacity is 74 litres and a range of 480 km (BMW, 2006). Whilst perhaps not a direct comparison, due to vehicle size differentials, the Toyota Prius has a range of 960km using a 45 litre fuel tank<sup>2</sup>. A typical petrol car has a cruising range of about 400 km. If the BMW was used as a single fuel vehicle, it would need a LH<sub>2</sub> tank twice it's current size to achieve a range of 400 km.

Hydrogen is stored on board the BMW at -253 °C under relatively low pressure in a heavily insulated tank. Unlike petrol, the evaporation leak rate can be significant due to heat gain. A fuel cell is used on board to generate the electricity for the car's auxiliary power. The car needs a relatively large amount of storage space for fuel, due to the two tanks, one of which has an insulation thickness of more than 200mm. It is no coincidence that BMW chose the largest model in their range to launch hydrogen as a fuel. Figure 2-2 shows the complexity and components required to store liquid hydrogen on board.



**Figure 2-2 Typical liquid hydrogen on board storage tank**  
(Schubert E et al., Unknown, p31)

Mazda are another car company with a vehicle that uses hydrogen powered ICE. The two main differences between the BMW and Mazda vehicles are the fact that Mazda store hydrogen on board in gaseous form and that they use Mazda's rotary engine. It is claimed that the rotary engine is particularly suitable for burning hydrogen. As in the case of the BMW, it is a dual fuel vehicle with

<sup>2</sup> Data supplied from Toyota technical literature for Prius model

hydrogen and petrol storage tanks. It was noted in the report that when running in hydrogen mode, the engine power output was reduced and that hydrogen combustion was “noticeably louder”. The report also interviewed Mr. Kashiwagi, Mazda’s hydrogen program manager who commented that hydrogen fuel cells were “expensive and not reliable enough”, perhaps justifying the Mazda approach (Birch S, 2009).

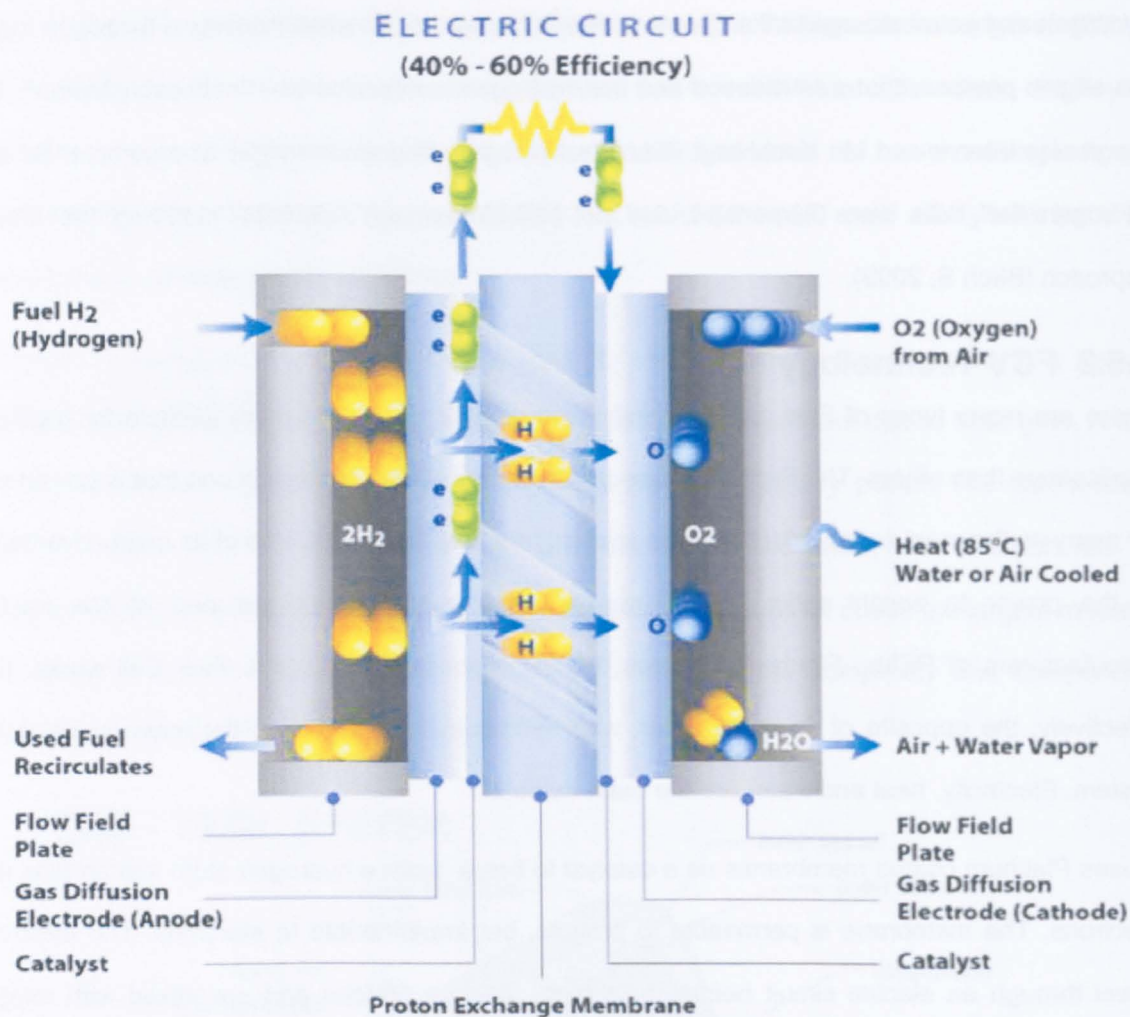
### 2.5.2 FCV Technology

There are many types of Fuel cells currently being developed, some more suitable for transport applications than others. The Proton Exchange Membrane (PEM) fuel cell is one that is considered by many as the most suitable for transport applications (Ballard, 2009). One of its main advantages is the power to weight ratio. Ballard power systems of Canada are one of the leading manufacturers of PEMs. Figure 2-3 shows the basic principles of how a Fuel Cell works. It is effectively, the opposite of an electrolyser, with hydrogen and oxygen as the main inputs to the system. Electricity, heat and water are the main outputs.

It uses Platinum coated membranes as a catalyst to break down a hydrogen atom into protons and electrons. The membrane is permeable to protons, but impermeable to electrons. The electrons travel through an electric circuit before they rejoin the free protons and are mixed with oxygen molecules. In this way the anode of the fuel produces electricity to drive a motor and the cathode creates heat and water.

Fuel cells can produce power at efficiencies much higher than most conventional power systems such as internal combustion engines (Johnston B et al., 2005). The efficiency of the fuel cell is dependent on the purities of the gases used and the control of the operating conditions. They typically operate at around 80 deg C and at about 1.5 bar pressure. The performance of the fuel cell can easily be affected by impurities (CUTE, 2006, p98).





**Figure 2-3 Typical Proton Exchange Membrane (PEM) Fuel cell**  
(Ballard, 2009)

There are still many technical challenges to overcome, in particular cost reductions and product life of the units. PEM fuel cells are generally developed as “single fuel” vehicles and as there is no significant hydrogen fuelling infrastructure in place it is difficult to see how they will be more than “demonstrators” without a hydrogen supply and distribution system in place. A more suitable application would be for fleet vehicles (e.g. buses or service vans) with refuelling in their own depot, although these vehicles have other important criteria to meet such as high reliability, low cost and long life of the units, all of which need to be considered for an FCV fleet vehicle

Currently, PEM Fuel cells and the associated equipment required to operate them are a significant cost increase to the overall the price of a hydrogen powered vehicle. According to Alan Coney, project manager of the CUTE bus trials, the PEM fuel cell buses cost approximately £850,000 each compared with the cost of a diesel equivalent bus at £130,000; in fact the fuel cell stack alone cost about the same a diesel bus (Coney A, 2004). It is probable that this very high cost is most likely due to the development costs and relatively low production numbers involved.

### 2.5.3 Hydrogen vehicle supply distribution systems

Unlike the other alternative vehicles so far, hydrogen powered vehicles would require a completely new supply and distribution system. Hydrogen is a completely new transport fuel (or energy carrier) compared to the existing options. It may appear that gaseous hydrogen could be considered similar to Compressed Natural Gas (CNG), and liquid hydrogen distribution similar to Liquefied Petroleum Gas (LPG), but hydrogen has completely different properties in terms of storage pressures and temperatures. Hydrogen supply and distribution systems will be discussed in more detail in chapter 3, but of the options reviewed here, it is clear that hydrogen is the alternative fuel with the largest obstacle to overcome in terms of a supply and distribution system.

### 2.6 Comparison of alternative technologies

This brief review of alternative technologies has highlighted the difficulties of identifying one clear solution based on cost of vehicle, type of fuel, emissions, and fuel distribution systems. Table 2-1 below is a summary of the present situation. It considers a Ford focus as the typical base petrol case and compares this with the alternative vehicles reviewed in this chapter. It should be considered as indicative only with respect to costs and emissions due to the assumptions made and explained in the table.

Vehicle	Fuel consumption (miles per gallon) & typical cost	Vehicle emissions (g CO <sub>2</sub> / km)	Approximate Cost
Ford Focus 1.4 styles (conventional petrol)	42.8 (12.7p/mile)	157	£14,300 [1]
Volkswagen Polo 1.4 Blue motion (diesel)	74.3 (7.9p / mile)	99	£14,500 [1]
Honda Civic 1.4 EMA ES (hybrid)	61.4 (8.9p / mile)	109	£16,265 [1]
Citroen C1 ev'ie Li Ion (electric)	0.23 kWhr / km 0.94 p / km	113 / 0 [3]	£16,850 [1]
Generic hydrogen powered vehicle (PEM Fuel cell )	0.025kg h <sub>2</sub> / km 8.9 p / mile [4]	257 / 676 / 0 [2]	£25,400 [5]

Table 2-1 Comparison of vehicle costs and emissions

- [1] Data largely obtained from “What Green Car” website (What Green Car, 2009) in the case of the C1 ev'ie it is recognised that it is a slightly smaller vehicle.
- [2] Figures are based on (1) Hydrogen produced by SMR, (2) Hydrogen produced from electrolysis using UK average mix, (3) Hydrogen produced from electrolysis using renewable electricity.
- [3] Figures are based on (1) charging using UK average mix electricity, (2) charging using renewable electricity.
- [4] Based on interpolation of CUTE fuel consumption figures (pro-rata'd for 60kW FCV) and cost assumption of hydrogen at £2.25 / kg.



[5] Since hydrogen FCVs are not yet on sale in car showrooms, costs are estimated. There are wide variations in the cost of FCVs. The figure used is based on a study of alternative vehicle technologies by researchers at Imperial College, London (Offer G et al., 2010)

Hydrogen FCV costs are estimates only, and included for comparison with other technologies. Fuel costs and emissions are highly dependent of the methods of production and distribution. It is important to note that hydrogen is the only fuel listed which is exclusive of any taxes which may be applied such as VAT and fuel duty. The table appears to show electric vehicles as having a significant advantage in terms of cost (both capital and operating) and emissions in some cases, but it should be noted that the Citroen is a smaller vehicle than the others. At the time of writing most electric vehicles that have reached the market tend to be small city vehicles. . Whilst battery electric vehicles may be suitable for short range fleet vehicles, they are not yet suitable for long range fleet vehicles such as coaches and lorries, or private cars that are required to make single long distance journeys.

However, it is not just the capital and operating cost of the vehicle which needs to be considered. Table 2-2 reviews the issues of cost, technology, vehicle emissions and energy security using a “traffic light” system to code the various stages. Based on the UK, it is the author’s attempt to highlight some of the issues discussed here. Using this approach, only hydrogen has no major issues but has significantly more minor concerns to overcome.

	Production				Distribution			End use		
	Cost	Technology	Emissions	Security	Cost	Technology	Emissions	Cost	Technology	Emissions
Efficient diesel engines										
CNG vehicles										
LPG vehicles										
Biofuels		[3]								
Battery powered electric vehicles								[1]	[1]	
Hydrogen powered FCVs							[2]			

Table 2-2 Summary of vehicle fuel issues for the future vehicle technology

- Key :-
- Green = No concerns - Costs are relatively low and well known. Technology is current in existence. Emissions are low and it is perceived as environmentally friendly. In terms of energy security, it offers the potential for countries to be independent with respect to the source of the fuel.
  - Amber = Minor concerns – Costs are higher than desirable, there are some technology issues to be addressed but perhaps not insurmountable. Emissions are not at a desirable



level but perhaps acceptable. Energy security, whilst not ideal is not an obstacle that cannot be over come.

- Red = Major concerns Costs are unacceptably high, There are significant technological barriers which may not be possible to overcome. Emissions are at a level which is unacceptable at the current time. Energy security is a limiting factor, with significant dependence on external sources for energy.

#### Notes:-

- [1].The negative issue with cost and technology is battery energy storage rather than electric vehicles.
- [2].Emissions can be eliminated if road transportation is powered by FCV trucks.
- [3].The limitation is on the potential to have sufficient land space to grow sufficient crops for large scale use of bio-fuels rather than the technology to produce bio-fuels. Although one could argue that the 2<sup>nd</sup> and future generation of bio-fuels required to improve yield and reduce land space requirements are technology issues.

If the aim is to eventually exclude hydrocarbons, it would seem that that only hydrogen or electricity can achieve this, although Bio-fuels may also be an option. It is not yet clear which technology has the most potential. Hydrogen has potential in terms of flexibility of production and end use (ICE or FCV). It also has potential for zero emissions. It does however, have a distinct disadvantage with the lack of a fuel distribution system. BEVs have some advantages over hydrogen but suffer from the three key obstacles of battery cost, weight and charging rates.

It is quite likely that vehicles in the future will be powered by electric motors. It may be that the "alternative technology" is more a question of which is the best on board energy storage and conversion technology, ie: electric batteries or hydrogen and fuel cells?

## CHAPTER 3 HYDROGEN TECHNOLOGY

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This chapter focuses on a literature review of current hydrogen technology, with a particular emphasis on industry and current hydrogen use. It does not address current hydrogen research which will be reviewed in chapter 4. A hydrogen pathway consists of three main elements, production, distribution and use. Vehicle technology with respect to a hydrogen powered vehicle (use) was reviewed in chapter 2. In this chapter the focus will be on the production, storage and distribution technologies

The current market for hydrogen is almost entirely based on industrial use in a variety of processes, mainly in the petro-chemical industry. Most of these processes take place within industrial complexes and the distribution systems required for transfer are usually by pipeline between the production facilities. When the point of use is either remote from production, or the quantities of hydrogen required are small and do not justify on site production, hydrogen is transported by road (in both liquid and gaseous state). Before considering hydrogen as a future energy source for road transport, it is important to understand the current markets and supply chains for hydrogen with the UK.

Whilst this research is primarily concerned with hydrogen for fleet vehicles, nominally within the UK, the review is not limited to the UK. It will generally be UK focused, although comparisons and references are drawn from within Europe as markets and distribution / infrastructure are similar. Production technology reviews will not be limited by geographic boundaries as most technology is applicable world wide.

### 3.1 Current use in the UK

Very little of the current hydrogen production is used in transport, consequently hydrogen fuel requirements for vehicles needs to be considered in addition to the current production figures. Hydrogen is used in oil refineries to produce fuels such as low sulphur diesel. If vehicles converted to hydrogen, there would be a fall in the use of hydrogen in refineries. This is quite a complex figure to quantify as refineries are multi-stream processing facilities which both produce and use hydrogen. The issue of hydrogen balance and the increased need for hydrogen in refineries due to fuels such as low sulphur diesel is addressed in a paper by Fonseca which looks at optimisation of refinery hydrogen and is useful further reading on this subject (Fonseca A et al., 2008). If there were to be a significant uptake of hydrogen vehicles this may reduce refinery consumption of

hydrogen and would in theory increase the amount of hydrogen available for export and hence transport. However, due to the refinery interactions, variations in sulphur content in the feed, it is difficult to quantify figure.. In 2002, the main uses for hydrogen worldwide were:-

- Ammonia production = 40.3%
- Oil refining = 37.3%
- Methanol production = 10.0%

(Watkiss P and Hill N, 2002, p23)

In 2006 the total UK hydrogen production was 58,834 tonnes (ONS, 2006). A typical break down of the way hydrogen is used is shown below:-

- 44% - was produced and consumed on site.
- 33% - was supplied by pipeline
- 23% - was transported by road trailer

(Watkiss P and Hill N, 2002 ,p23)

To put these figures in context, a typical London bus might travel about 60,000km in a year. The recent CUTE trials in 2006 reported that a hydrogen fuel cell powered bus achieved an average consumption of 0.25kg H<sub>2</sub> / km (CUTE, 2006, p67) so this would require about 15 Tonnes of hydrogen per bus per annum. If all the hydrogen transported by road in the UK in 1996 was diverted for transport use, it would only provide sufficient energy for about 435 buses, less than 6% of London's current bus fleet<sup>3</sup>. Fuel consumption is based on CUTE +50% improvement as reported in bus trials in Hamburg (Fuel cells bulletin, 2009)

More recent data on hydrogen production and capacities are difficult to obtain, as producers consider this commercially sensitive. An informal email survey sent out to the major UK producers provided very few responses. The Office of National Statistics (ONS) produces data on industrial gases, but do not appear to record transportation of hydrogen for the domestic market (only imports and exports). Even some of the earlier data supplied by the ONS is withheld from their production figures as "suppressed as disclosive".

Table 3-1 shows ONS figures for the years 2003 through to 2006. Whilst it does not reveal the quantities of hydrogen transported within the UK, it does show total imports / exports (and hence transported). According to the ONS data, hydrogen production in the UK is increasing, but the total UK production in 2006 would only be sufficient for about 5,700<sup>4</sup> hydrogen powered fuel cell buses, still less than the current London bus fleet.

<sup>3</sup> Current London bus fleet size is 6800 according to Transport for London website

<sup>4</sup> Based on an annual distance of 60,00km per bus and an estimated consumption of 0.17kg/km



	2003	2004	2005	2006
<b>Total UK production (Tonnes)</b>	36,063	39,463	55,271	58,834
<b>Total Imports / exports (Tonnes)</b>	582	146	160	333
<b>Imports / exports as % of production</b>	1.61%	0.37%	0.29%	0.57%

**Table 3-1 UK hydrogen production figures**  
(ONS, 2006)

### 3.1.1 UK hydrogen production centres

Apart from the fact that we currently only transport a small amount of the hydrogen needed for vehicles by road, the locations of production plants are not evenly dispersed within the UK. They are generally located in clusters near to the large scale industrial complexes such as oil refineries, which are the main users. The main production areas are:-

- North East (Teeside)
- North West (Ellesmere port area)
- South Wales (along the M4 corridor)

If hydrogen were to be used as a transport fuel, the largest demand centres are likely to be around the most densely populated areas - London and the South East, Birmingham and the Midlands, Manchester and the North West. In the case of London and Birmingham, a significant supply chain would be needed from the point of production to the point of use.

### 3.1.2 UK hydrogen capacity

Plant utilisation can be defined as the plant production divided by plant capacity (expressed as a percentage), ie: it is a measure of what spare capacity the plant has to increase production. As part of the email survey mentioned earlier, producers were also asked for data on plant utilisations and spare capacities. Again (perhaps not surprisingly), the responses were very negative. Some of the respondents did not reply, and the few that did were not able to answer most questions due to it being “commercially sensitive data”. Although total production figures are available from ONS, this hydrogen is already in use and is not helpful when trying to ascertain spare capacity. If we were to use hydrogen for transport, utilising existing production plants, this would need to come from spare production capacity. It is reasonable to assume a typical utilisation figure of 68%<sup>5</sup>, using the ONS data for 2006, this would indicate that if all UK production plants were to produce at 100% of capacity, the total hydrogen available would still only be approx 27,000 Tonnes, sufficient to keep

<sup>5</sup> This data was taken as an average of UK production plants, from a source of data which is confidential.

approximately 2,700<sup>6</sup> London buses on the road. It is clear that new additional hydrogen plants would need to be built for even a relatively small uptake of hydrogen powered vehicles.

### 3.1.3 UK hydrogen pipelines

Currently there are no significant dedicated hydrogen pipeline routes within the UK. Most existing pipelines merely link the industrial plants within the same complex to use the hydrogen directly. Within Europe there are 1500km of hydrogen pipelines, the longest being between France and Belgium at 400km. The Ruhr pipeline in Germany is 210 km, with an operating pressure in the range of 10-20 bar pressure and has operated safely for more than 50 years (Kruse B et al., 2002). These European examples demonstrate that it is possible to install dedicated hydrogen pipelines, but at present this facility does not exist in the UK. Whilst we have an extensive natural gas pipeline system within the UK, it cannot be converted to hydrogen for a variety of reasons:-

- These pipelines are already needed to carry natural gas to customers.
- Hydrogen has a lower density than natural gas (Kruse B et al., 2002). A 50 bar pipeline could transport five times the amount of energy carrying natural gas than if the same pipe was carrying hydrogen<sup>7</sup>. Consequently hydrogen pipelines require either, larger diameter pipes than those used for natural gas, or faster velocities which would require greater compression.
- Pipeline materials used for natural gas may not be compatible for pure hydrogen. High carbon content steels and plastics, such as PVC / HDPE are too porous (Kruse B et al., 2002).
- It is possible to transfer a mixture of hydrogen and natural gas (sometimes known as "Hythane" ) but this would require further separation before use.

In addition to this, the national gas grid operates on a reducing pressure system. The main transmission lines, known as the National Transmission System (NTS) operate at approximately 85 barg. These feed into the Local Transmission System (LTS) which operates at up to 38 bar g. and finally the Local Distribution System (LDS) operates pressures between 2 and 7 barg (Competition commissioners office, 2010). This is because most natural gas is used at low pressure. Hydrogen, by contrast, is likely to be stored and used at high pressures due to low molecular weight.

Overall, it is concluded that at present, there is not a suitable pipeline system for distributing hydrogen gas in the UK. It would appear that the existing Natural gas system would be required to be larger and of different materials. In effect, a new pipeline system is required.

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<sup>6</sup> Based on an annual distance of 60,000km per bus and an estimated consumption of 0.17kg/km

<sup>7</sup> Assumes 50 bar pressure with density of natural and hydrogen at 50 kg/m<sup>3</sup> and 3.95 kg/m<sup>3</sup> respectively



### 3.1.4 Future hydrogen supply systems

A paper by on the evolution of size and cost of a medium hydrogen delivery infrastructure for vehicles in Europe by Tzimas in 2007 claimed that *"the cumulative capital necessary to build this infrastructure [hydrogen] by 2050 may range between 700 and 2200 thousand million Euros for the most optimistic scenario and is significantly lower for the other scenarios. Most of this will be needed for the development of the distribution network. These costs however represent a relatively small fraction (7.5–22%) of the annual gross value added of the energy sector."* (Tzimas E et al., 2007). In this context Tzimas defines the most optimistic scenario as high vehicle uptake rates compared with a pessimistic scenario as lower vehicle uptake rates during the period of the study. The infrastructure is defined as including all elements required to take the hydrogen from the point of production to end use and includes pipeline networks and trucks required for distribution. It should be noted, however, that as no clear distribution system has emerged, these estimates are merely approximations based on assumptions of likely pathways. What is clear is that any new hydrogen distribution system will require significant investment.

Based on typical hydrogen costs and bus fuel consumption figures in 2006<sup>8</sup>, fuel costs of a hydrogen powered fuel cell would be £0.32 per km and those for, an equivalent diesel powered bus would cost approx £0.18<sup>9</sup> per km. Although this is more expensive it is necessary to consider that the hydrogen cost is "at the factory gate" and the diesel cost is "at the pump". Consequently, if hydrogen supply and distribution costs are significant, it will not be so competitive. This issue will be addressed in more detail later in this research.

### 3.1.5 Summary of current hydrogen supply

So far, this review has shown that, currently, there is insufficient spare production capacity for anything but small scale demonstration projects such as the recent CUTE project in London. Also, what spare capacity that does exist, is not located conveniently for the most likely areas of hydrogen demand. Furthermore, it is likely that the existing supply chain (road transport) would need to be expanded significantly to handle any increase.

Even a limited hydrogen bus fleet would require significantly more hydrogen than is currently available and transported. Consequently new production facilities are required. From a technology point of view, production can be increased to match demand simply by building larger production

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<sup>8</sup> Figure based on ONS data (2006) @ £1.26 per kg, and CUTE average consumption figure of 0.25kg/km. Costs are Nett of taxes and duty.

<sup>9</sup> Figure is based on diesel @£1.10 per litre and average equivalent diesel bus consumption figure of approximately 6 mpg. Costs are Nett of taxes and fuel duty.

facilities on existing sites, although the cost of these additional facilities would be significant. However, if transportation of hydrogen is either an economic or technical barrier to a hydrogen economy, this may not be the best solution. The existing supply chain would require such a significant expansion, that it might be a better solution to consider a completely new distribution system, eg: pipelines or for new production to be located close to where the hydrogen will be used.

## 3.2 Hydrogen Technology

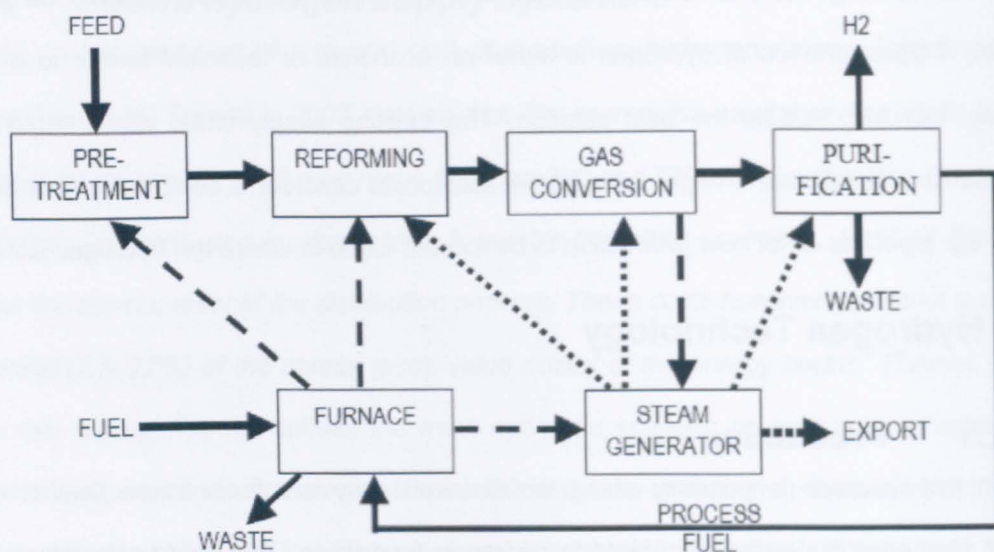
### 3.2.1 Production

Although this research is primarily about the distribution system for a future fleet of hydrogen vehicles, the issue is necessarily linked to hydrogen production. This section therefore identifies some of the more common processes by which hydrogen can be produced. There is a significant amount of research being conducted on novel technologies, but these are mainly for small scale production and many are in at the prototype stage. Hydrogen production by reforming is the cheapest and most energy efficient method of mass production with approximately 96% of current world produced using reforming processes (Lovins A, 2003, p8). However reforming processes produce significant amounts of carbon dioxide which negates the "clean fuel" claim of hydrogen.

#### 3.2.1.1 Steam Methane Reforming

Steam Methane Reforming (SMR) is a chemical process whereby hydrocarbon feed gas, such as natural gas ( $\text{CH}_4$ ) is mixed with steam ( $\text{H}_2\text{O}$ ) in a high temperature reaction process to produce synthesis gas (Syngas), which is a mixture of hydrogen and carbon monoxide ( $\text{CO}$ ). Some of the  $\text{CO}$  further reacts with  $\text{H}_2\text{O}$  to generate carbon dioxide ( $\text{CO}_2$ ) & hydrogen ( $\text{H}_2$ ). A by-product of this process is heat, which is recovered in the form of steam. Figure 3-1, shows the basic stages involved in this process. The process is a chemical reaction in two stages:-





**Figure 3-1 Typical SMR Process**  
(Molburg J and Doctor R, 2003)

Energy efficiencies of around 72% (Lovins A, 2003) are often quoted, but this is only if a use is found for the steam. Otherwise the efficiency of the process drops significantly to be below 50%. Consequently, SMRs may not be particularly energy efficient as dedicated hydrogen producers unless linked to other processes that use the heat. Table 3-2 lists the main inputs and outputs of a typical small scale SMR process. For every 100kg of hydrogen produced, a use has to be found for 711kg of steam. For large scale, centralised production facilities, this is not an issue as the steam can be used for utility supplies such as heating or electricity power generation.

Inputs		Outputs	
Electricity	68 MJ	Steam	711 kg
Natural gas	349 kg	Hydrogen	100 kg
Boiler feed water	1270 kg	Boiler blow down	28 kg
Combustion air	Balance	Flue gas	Balance

**Table 3-2 Typical SMR mass balance**  
(Long R, 2010)



### 3.2.1.2 Partial Oxidation Reforming (POX)

This process is similar to the SMR process (see Figure 3-2 ), but it also requires large amounts of oxygen, which has to be supplied from a separate air separation plant and has additional by-products. Both processes produce Syngas as their primary product.

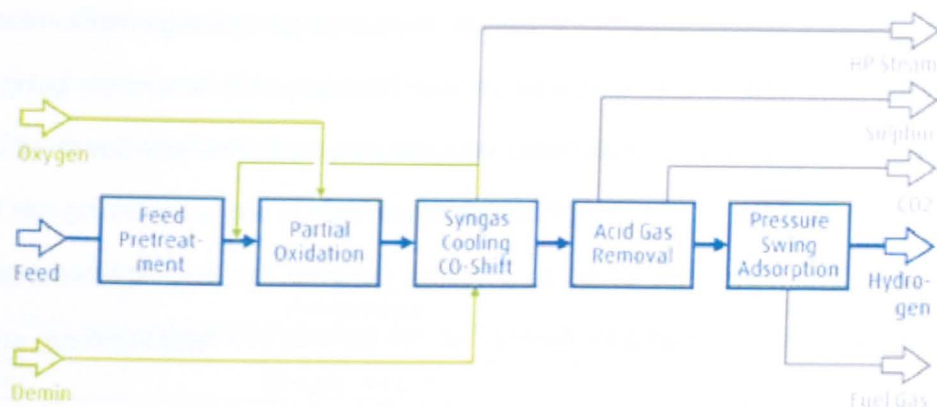


Figure 3-2 Typical POX Process  
(Linde, 2009)

### 3.2.1.3 Hydrogen production from Biomass

Biomass as a fuel was discussed to a limited extent in section 2.3, when it was considered as a bio-fuel. It can also be used to produce hydrogen, the feed stocks are similar and they all require conversion into a liquid or gaseous form by processes such as pyrolysis or gasification. The gas is then converted to hydrogen by the same type of reforming processes described previously. These processes have some environmental advantages over hydrocarbon based feed stocks, especially with the potential use of waste products as discussed earlier in chapter 2. The type of feedstock used will impact on the “green” credentials of biomass whether used directly or converted to hydrogen.

### 3.2.1.4 Low pressure / temperature electrolysis

This process involves passing an electrical current through water via electrodes. Gaseous hydrogen is formed at the negative electrode and oxygen at the positive electrode. The primary feed is electricity and water. Electrolysers are used to produce high purity hydrogen (necessary for use in PEM fuel cells) and it has been produced by this method for many years. However, only about 4% of the world’s hydrogen is produced by electrolysis at present (Lovins A, 2003 ,p8).

Electrolysis is suitable for both small scale production, typically 150 kg/day as used in the CUTE project and large scale production, typically 50,000 kg/day as used in the US DoE hydrogen models (US DOE, 2009). An electrolyser also produces oxygen which is usually vented. The CUTE

demonstration project used approx 64 kWh of electricity per kg of hydrogen produced (Binder M and Faltenbacher M, 2006, p33). The cost and emissions of the hydrogen is highly dependent on the cost of electricity and method of generation.

#### **3.2.1.5 High temperature electrolysis**

As water temperature rises, the energy needed to separate the water into hydrogen and oxygen is reduced. This process may be suitable for use with nuclear power which generates electricity and has high temperature water available as a by-product. Nuclear power is currently going through a renaissance and the government White Paper advocates the use of nuclear power as part of any future UK energy mix (BERR, 2008,p10). If nuclear power were to play a continuing role in the UK's electricity generation, then there could be a future potential for the combined production of electricity and Hydrogen. This particular synergy has not featured in energy policy.

#### **3.2.1.6 Hydrogen by thermal separation**

Thermolysis causes water to divide into hydrogen and oxygen thermally at elevated temperatures, typically above 2000°C (NREL, 2008b). The technology for this process is relatively novel and currently appears to be limited to small scale production prototypes. There are likely to be some technological challenges of operating at such elevated temperatures, specifically in the field of materials technology. This process requires the input of a significant amount of heat that typically would need to come from either solar radiation or nuclear reaction. Both thermal separation and high temperature electrolysis may have future potential if a new generation of nuclear power plants are built in the UK.

#### **3.2.1.7 Other Hydrogen technologies**

This review so far has focused mainly on reforming processes and electrolysis, with a brief overview of hydrogen production from biomass and thermal separation. Hydrogen can be recovered from gas mixtures using filtering processes such as membranes or pressure swing adsorption (PSA), but as the hydrogen tends to be a part of other chemical processes; it is unlikely that these methods will be a significant source of hydrogen for transportation purposes. Hydrogen can also be produced from relatively novel technologies such as biological and photo- electrical processes, but review is considered outside the scope of this research

### **3.2.2 Summary of production techniques**



Table 3-3 summarises the advantages and disadvantages of the various production processes. The technology already exists to produce hydrogen in large quantities, although not necessarily in an environmentally friendly manner. It appears that production technology is not an obstacle to a hydrogen economy, although it is not clear that any one particular process will be the best fit option for all situations. This may not be a problem as hydrogen processes evolve with technology developments. What is likely to be more of an issue is whether the processes can be used for both large and small scale production and consequently where the plants have to be located. It is also likely that by-products and emissions may limit their feasibility.

	Advantage	Disadvantage
<b>Reforming (SMR &amp; POX)</b>		
Technology	Simple, mature	
Production	Both large and small scale	
Feedstock		Hydrocarbons
Product purity		Low – further purification required
By-products		CO <sub>2</sub> and NOX
<b>Electrolysis (high and low temperature)</b>		
Technology	Mature	
Production	Both large and small scale	
Feedstock	Water, electricity	
Product purity	High	
By-products	Oxygen	Depends on electricity generation method
<b>Thermal separation</b>		
Technology		Complex
Production		Large (significant heat source req'd)
Feedstock	Water / Heat	
Product purity	High	
By-products	Oxygen	

Table 3-3 Summary of hydrogen production techniques reviewed

### 3.2.3 Summary of production costs

Table 3-4 summarises typical costs for the various production processes reviewed. It should be noted that these costs are often estimations due to the fact that technology is still being developed or because producers do not generally release such information to the public. Only reforming and electrolysis process technologies are mature and hence reliable costs exist. For other methods, the costs below should be considered as a best estimated range. Most hydrogen production processes use significant amounts of electricity and / or natural gas. Costs have been adjusted in accordance

with the standard factors used in this research (refer to clarifications for details), although it is worth noting that as the data spans a number of years, there may be some variations in the actual costs compared with the cost adjustments made here

To give some guidance of current hydrogen costs, the Office of National Statistics quote the sales value of hydrogen produced in the UK between 2003 and 2006 as £0.87 and £1.26 per kg respectively (ONS, 2006).

System	Cost £ / kg H <sub>2</sub>	Remarks
SMR reforming	£0.52 to £0.70 (Simbeck D and Chang E, 2002) to £1.42 to £3.53 (Shayegan S et al., 2006)	Large scale production Plant size 150,000 kg/day  Small scale production Plant size 800 to 100 kg/day respectively
POX reforming	£0.78 to £1.32 (Watkiss P and Hill N, 2002)	Partial oxidisation of heavy hydrocarbons. Significant CO <sub>2</sub> produced. CO <sub>2</sub> removal would increase costs by 25%
Biomass	£0.70 to £1.32 (Watkiss P and Hill N, 2002)	Forecast costs based on partial oxidisation of biomass. Costs dependent on feed stock used. It is considered carbon neutral
Electrolysis of water	£2.66 to £2.80 (Simbeck D and Chang E, 2002) to £3.63 to £4.12 (Shayegan S et al., 2006)	Plant size 150,000 kg / day  Heavily dependent on electricity costs. Plant size 100kg/day
Thermolysis	£0.75 (estimate)	Forecast figure only based on hydrogen production as part of a nuclear power plant

Table 3-4 Summary of hydrogen production costs

Perhaps a more appropriate comparison of costs is to compare hydrogen with diesel. However, to draw an accurate comparison we need to compare the costs in terms of energy (GigaJoules). For the two fuels, this is easily calculated by dividing the cost per kg by the Lower Heating Value (LHV) of the fuel in GJ / kg. The figures below are calculated Nett of taxes, i.e. the VAT and fuel duty applicable to diesel has been deducted from the forecourt cost of diesel

- Hydrogen at £1.26 / kg equates to £10.50 / GJ<sup>10</sup>
- Diesel at £1.10 per litre equates to approximately £9.92 / GJ

The figures above show that hydrogen as an energy carrier can compare reasonably well with diesel as a fuel in terms of cost. These figures may contradict slightly with the bus performance figures earlier in section 3.1.4, this is because the bus figures take into account additional efficiencies of an FCV hydrogen bus compared with an ICE diesel bus. If the hydrogen bus was

<sup>10</sup> Based on factory gate cost of hydrogen in 2006, corrected for inflation to 2008

powered by an ICE, the figures quoted here would be more appropriate as they would then be a direct energy comparison using the same type of technology (ICE) and hence efficiencies. Again hydrogen distribution costs need to be added. All hydrogen costs so far are approximations only. more precise costs will be used in the modelling work in chapter 8.

### 3.3 Hydrogen storage and distribution

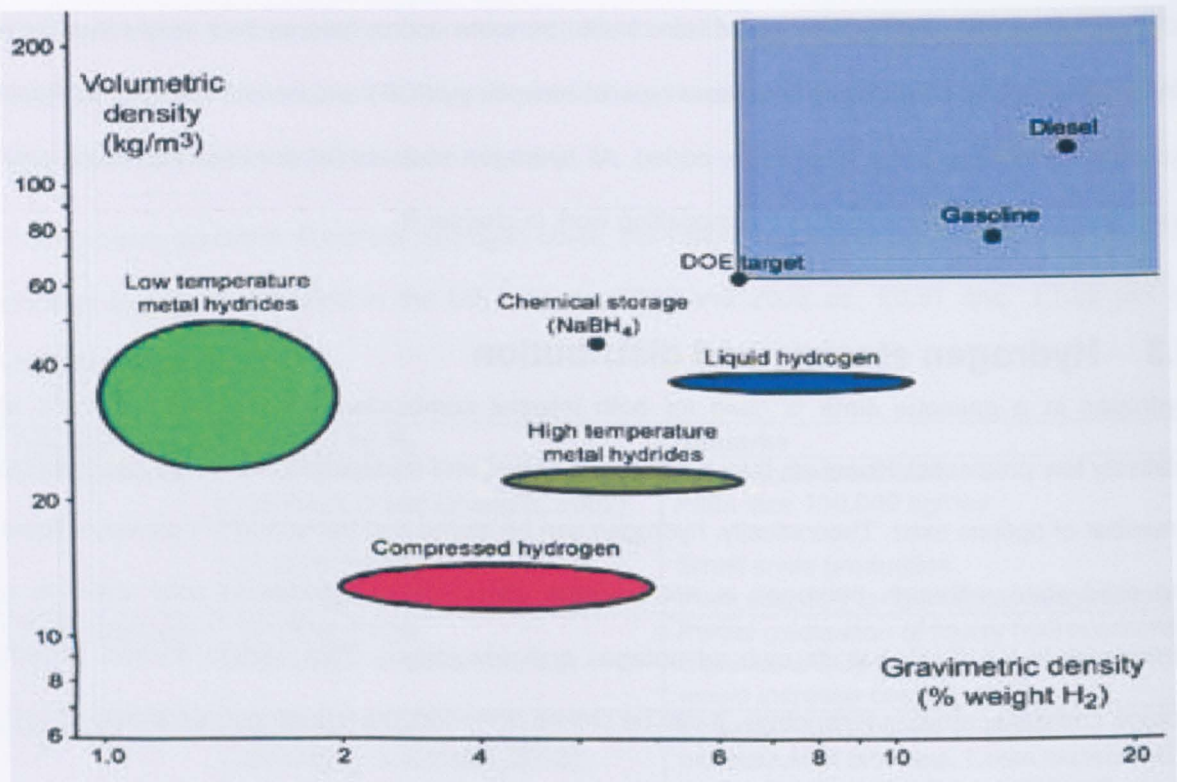
Hydrogen in a gaseous state is used for both internal combustion engines and fuel cells at relatively low pressures. However, how hydrogen is stored and transported is a linked issue where a number of options exist. Theoretically, hydrogen can be stored and transported in gaseous, liquid and solid state, although hydrogen is not currently stored or transported in solid state on a commercial basis. Each has its own advantages and disadvantages. This section reviews current storage and transportation technology. It can be broken down into the following three areas:-

- Static storage (as required for production and distribution centres)
- Transportation (how it is stored whilst in transit)
- On board storage (as stored on board vehicles)

Static storage is the least of the storage problems for hydrogen. Generally there are no limitations on size and weight of the storage vessels. Industry has many years of experience of storing hydrogen in both gaseous and liquid state, and the technologies and materials are relatively mature.

The limitations of transportation carrying capacity of hydrogen were identified in Table 1-1. Significantly more journeys are required if hydrogen is to be transported by road from centralised production facilities. This adds significant cost to the distribution system and if the tankers are hauled by diesel powered lorries, additional CO<sub>2</sub> emissions. Even allowing for fuel cells being twice as efficient as the internal combustion engine [ICE], there would be considerable logistical difficulties to supply all future hydrogen use by road transport.

On board storage is perhaps the most difficult obstacle in terms of technology. It is not just the size and weight of the hydrogen but also materials of the storage tanks required to carry the hydrogen. Consequently the issue of storage density is crucial. The diagram below gives typical values of storage densities of various hydrogen storage states and pressures compared to common hydrocarbon fuels. These are "system" densities, ie: it includes the weight of the storage tank in the calculation.



**Figure 3-3 Typical storage system densities**  
(Royal Society of Chemistry, 2007)

It is clear that diesel and petrol have a significant advantage when compared with hydrogen. It is important to note here that this diagram relates to energy density rather than mass. Hydrogen at 120 MJ / kg has almost three times the energy value of some hydrocarbon based fuels.

In terms of density, liquid hydrogen is limited by the laws of physics at approx 62 kg/m<sup>3</sup>. Although it is possible to stored liquid hydrogen at higher pressures and hence increase density, the benefit is quite limited (refer to Table 4-2 for further information). It would therefore seem logical that the only potential for improvement is in the materials used for storage, and hence improvements in overall systems storage density. Gaseous hydrogen figures are based on typical current compression values. Further compression is possible, but significant improvements in density are limited. As with liquid hydrogen, the potential for future improvements seems to be limited to storage materials and overall systems storage density. Solid state hydrogen may present the potential for improvements in storage density. According to the US DoE *"Hydrogen storage in solids may make it possible to store larger quantities of hydrogen in smaller volumes at low pressure and at temperatures close to room temperature. It is also possible to achieve volumetric storage densities greater than liquid hydrogen because the hydrogen molecule is dissociated into atomic hydrogen within the metal hydride lattice structure"* (US DoE, 2010). Since gaseous and liquid hydrogen storage density improvements are mainly associated with storage material improvements, the view



of the US DoE seem reasonable, although it should be noted that this is a relatively new field of technology compared to other forms of hydrogen storage.

### **3.3.1 Gaseous hydrogen storage**

Hydrogen in compressed gaseous form currently stored at ambient temperature and high pressure is the most common method of transport and use. Since hydrogen compression is carried out in the same way as compression of natural gas, the procedure is well tested and readily available. New developments are mainly associated with optimisation. There is a wide range of available compressors for hydrogen, from several  $\text{Nm}^3/\text{h}$  throughput up to several hundred  $\text{Nm}^3/\text{h}$ , primarily used for the filling of stationary high pressure (200 – 300 Bar) and low pressure (10 - 50 Bar) storage tanks.

Because of the logarithmic relationship between pressure and work required for Isothermal compression ( $\text{work} = k \ln(P_{\text{out}}/P_{\text{in}})$ ) (Cengel Y and Boles M, 1989), the increased energy required for a higher filling pressure is not that great. Thus the compression from 1 to 300 Bar needs only 8% more energy than the compression from 1 to 200 Bar. Whilst it is technically possible to compress hydrogen to very high pressures, the costs for high pressure machines are much higher with material requirements and wall thickness of piping all adding significantly to cost.

### **3.3.2 Gaseous hydrogen distribution**

Compressed hydrogen is regularly transported by road at pressures of approximately 250 Bar. Rather than one storage tank, they are carried in multiple cylinders, which are bundled together with one common fill header point. Dedicated hydrogen pipelines exist in the UK, but usually remain within industrial complexes as mentioned earlier. It is technically possible to build a network of dedicated hydrogen pipelines, but demand needs to be high enough to make the investment viable.

Some manufacturers provide simplified guidelines for potential customers such as shown in Figure 3-4. However, these do not consider the supply chain length. The demand values are quoted in "SCF" / day, which is Standard Cubic Feet and the scale factor "MM" equates mathematically to  $10^6$ . To aid reading of the diagram 1MM SCFD is approximately equal to 2,600 kg/day. The coloured bands represent the recommended methods of hydrogen supply. These range from gaseous hydrogen in tube trailers at the lowest demand up to large on site production or pipelines for high demands.

According to Air Products, demands below approximately 1,250 kg / day are unlikely to make pipelines the cheapest cost option (refer to Figure 3-4). This means that whilst network flows may be sufficiently high enough to justify delivery by pipeline, the spurs to individual depots may not be cost effective.

### Hydrogen Supply Selection Chart

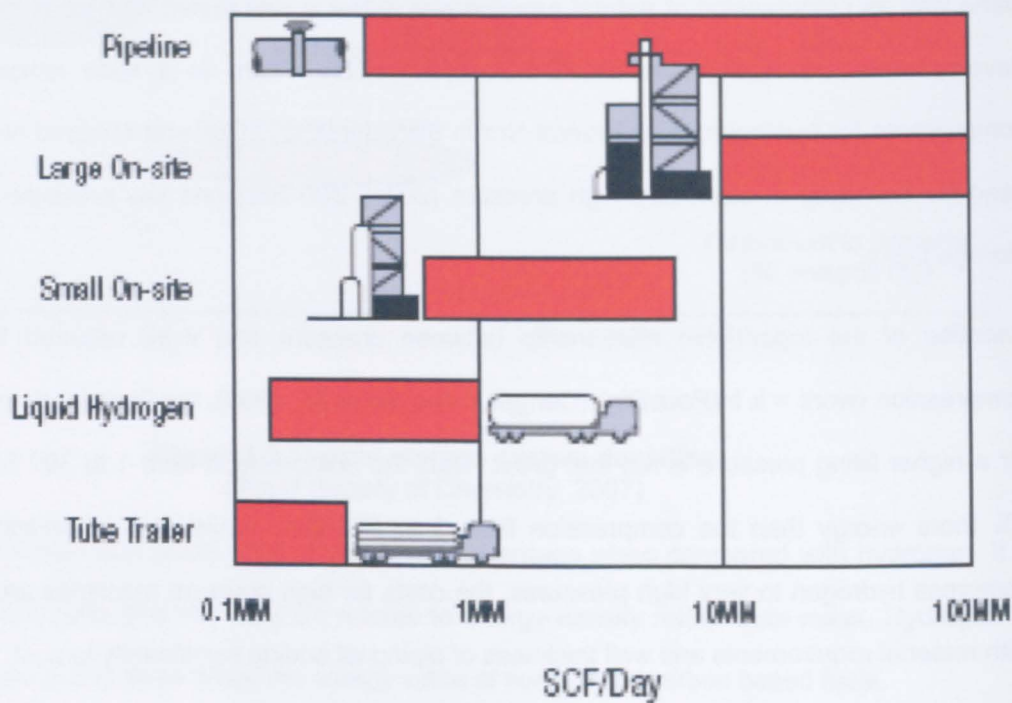


Figure 3-4 Typical hydrogen distribution options  
(Air-Products, 2001)

Costs of pipelines vary widely according to researchers. It is difficult to estimate a generic cost as a significant portion of pipeline capital costs are the related to the terrain the pipeline is required to be installed in. A review of pipeline costs in the 1990’s by Amos provides a range of pipeline costs which varied from £91,000 to £868,000 per km<sup>11</sup> (Amos W, 1998 ,p35). He also reported that natural gas pipeline estimation methods were often used to project costs of hydrogen pipelines.

#### 3.3.3 Liquid hydrogen storage

Before hydrogen can be stored in liquid form it requires to be cooled to -253°C. The liquefaction process is complicated by the fact that hydrogen has two Isomers, Ortho (with both atomic nuclei spinning in the same direction) and Para (with atomic nuclei spinning in opposite directions). At ambient conditions hydrogen exists predominantly in it’s Ortho state, but at temperatures close to

<sup>11</sup> All costs have been adjusted to 2009 prices based on standard conversions (refer to clarifications for details)



it's boiling point an exothermic conversion takes place converting from Ortho to Para, and as the reaction is exothermic it would cause significant boil off of the liquid (Berstad D et al., 2009, p 1561). A conversion stage is required which can be carried out using a catalyst to convert the Ortho hydrogen into Para hydrogen at a temperature of about -200° C (Domashenko A et al., 2002), before the hydrogen is liquefied to ensure that the exothermic reaction does not take place at the critical liquefaction temperature. The problem is that the liquefaction process requires a significant amount of energy, at least 30% of the energy value of hydrogen is used in the liquefaction process (Sorensen B, 2005, p88). This is a significant penalty in terms of energy efficiency. If hydrogen is required on board a vehicle in liquid form, it should be liquefied at the earliest point of the supply chain, for ease of transportation. Typical costs for hydrogen liquefaction are £0.66 / kg of H<sub>2</sub><sup>12</sup> (Paster M, 2006), which is a significant cost in addition to the overall cost of hydrogen.

A key element of liquid hydrogen is cold conservation. Hydrogen is not easy to sub cool below the liquefaction temperature, so relatively small increases in temperature can result in the liquid boiling off. It is therefore important to minimise boil off rates. The evaporation rate for large tanks can be quite small. The current state of the art for small scale, (i.e. transportable) containers is probably best demonstrated in the BMW 750H car (BMW, 2006). These tanks rely on multi-layered fibres to provide insulation. Due to the size limitations, losses can be in the range of 1-2% per day. Of course this is not an issue if the vehicle is being driven as the boil off gas can be used to drive the vehicle, but if the vehicle is parked for several days the hydrogen has to be vented into the atmosphere.

Whilst insulation technology is perhaps fully developed for large-scale storage where space is less of a premium, further work is required to improve the losses on smaller, on board storage systems.

Current options are:-

- Perlite (a generic term for naturally occurring siliceous rock), which is heated and expanded to provide a good insulation material.
- Fibreglass type insulation.
- Gas jacket cooling by maintaining a cryogenic blanket of a cheaper gas such as nitrogen between the inner and outer skin of the tank. This technology is limited to static tanks
- Vacuum jacketing, which is often used on cryogenic pipelines.

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<sup>12</sup> Original figures based on 2003, but converted to 2009 prices based on standard conversions (refer to clarifications for details)

### 3.3.4 Liquid hydrogen distribution

At present there is little transportation of liquid hydrogen by road within Europe, although the transportation of other cryogenic products such as oxygen and nitrogen are commonplace, so this technology is available for hydrogen if required. Costs for liquid hydrogen are cheaper than transporting gaseous hydrogen, and vary according to distance as shown in Table 3-5 (Watkiss P and Hill N, 2002 ,p21). Although transportation of hydrogen in liquid form is cheaper than in gaseous form (due to the different densities and hence carry capacities, it still lags behind hydrocarbons as shown in the fuel density comparison Figure 3-3.

Distance Miles	Transport cost £ / GJ	
	Liquefied	Compressed
10	0.2 to 1.0	3
100	0.3 to 1.2	7
200	0.7 to 1.4	12
500	1.3 to 2.0	27
1000	2.5 to 3.1	52

Table 3-5 Cost of transporting hydrogen by road  
(Watkiss P and Hill N, 2002)

There appear to be no liquid hydrogen pipelines in the Europe at present. A limited system is installed at NASA in the U.S.A, but this is only a few hundred metres long. Although technology exists at present to distribute by pipeline, the issue of cold conservation would limit the practical length of any liquid pipelines.

### 3.3.5 Other forms of hydrogen storage

Although the most common states for storing and transporting hydrogen is in liquid or gaseous form, it is possible to store hydrogen in “solid state”. This term is used to define various storage technologies, such as metal hydrides for example. A detailed review of the various types of solid state hydrogen storage technologies is considered outside the scope of this research. For further reading on this subject refer to “Solid state hydrogen storage materials and chemistry” (Walker G, 2008, p12) and “Hydrogen storage in Metal hydride systems and their derivatives” (Eberle U et al., 2006) .

The current status of this type of technology can be found at Fuelcellstore.com<sup>13</sup>, based in the USA. This company is currently marketing solid state metal hydride hydrogen storage canisters. A typical cost is \$800 for a canister containing about 0.08kg of hydrogen (Fuel Cell Store, 2008).

Hydrogen can also be stored in other forms such as alanates and borohydrides. This topic covers a wide number of material technology issues outside the author's field of expertise. For further reading, refer to "Novel hydrogen storage materials: A review of lightweight complex hydrides" (Jain I.P et al., 2010)

**3.3.6 Summary of storage and distribution techniques**

Table 3-6 below, summarises the advantages and disadvantages of gaseous and liquid hydrogen storage and distribution systems.

System	Advantages	Disadvantages
Gaseous	Generally cheaper storage tanks than liquid state Stored in same state as final use Easily transportable	Limited storage density Potentially dangerous to store / transport
Liquid	Good storage density Good system weight / fuel ratio	Liquefaction is expensive (energy intensive) Losses due to heat gain. Additional cryogenic safety factors. Needs converting back to gaseous state for use.

**Table 3-6 Summary of hydrogen storage and distribution systems**

The delivered cost of diesel in terms of energy was reported earlier in section 3.2.3 as £9.92 / GJ. At the same time, the factory gate price of hydrogen was reported as £10.50 / GJ. Some typical distribution cost estimates shown below and are adjusted to 2009 prices based on standard conversions (refer to clarifications for details). The distribution data is taken from Table 3-5 on the basis of a 100 mile (160km) delivery distance

- Liquefaction = £4.87 / GJ based on data from (Paster M, 2006)
- Liquid hydrogen distribution = £0.30 to £1.20 / GJ based on data from (Watkiss P and Hill N, 2002)
- Gaseous hydrogen distribution = £7.00 / GJ based on data from (Watkiss P and Hill N, 2002)

<sup>13</sup> A web store that markets fuel cell products and components (Fuelcellstore.com)

The addition of these costs distribution costs now produces a comparable set of 'at the pump' figures, which are:-

- Diesel = £9.92 / GJ
- Liquid Hydrogen = £15.67 to £16.57 / GJ
- Gaseous hydrogen = £17.50 / GJ

Hydrogen now becomes less competitive due to the significant distribution costs. It is at least 50% more expensive than diesel and significantly more expensive if transported in gaseous form by road. It should be noted that figures are based on ONS factory gate data and "estimates of costs" to transport and liquefy. It is also worthy of note that these figures are not consistent with the Air Products values used in Figure 3-4. However one should also note that in general the figures by Watkiss and Hill focus on supply chain length and the Air Products results focus on demand only. Considering the significant cost increases to transport hydrogen, more detailed analysis is required which ideally needs to take into account both demand and supply chain length. This point has been incorporated in the research of this thesis.

## CHAPTER 4 HYDROGEN RESEARCH

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So far this review has focused on the status of the current markets for hydrogen, alternative vehicle technologies as well as current production, storage and distribution technologies. It is now appropriate to consider research that has been conducted into these issues.

The fuel supply systems for hydrocarbon based liquid fuels have remained largely unchanged for many years now, although dispensing methods have evolved. Early fuel was sold in general stores in steel cans, later developments included hand carts and curb pumps eventually developing into the modern refuelling stations we have today (Melaina MW, 2007). One change in the fuel delivery system is perhaps the development of pipeline systems to enable bulk transfer of fluids to local supply depots. This is largely a consequence of increased centralisation in refining oil products and the fact that oil is easy to transport by pipeline. The supply chain is effectively fixed and not a consideration in terms of cost or environmental issues.

This is not necessarily the case for hydrogen. Whilst it may be cheaper to produce hydrogen centrally, if the supply chain proves to be expensive it may have a more significant effect on the overall cost of the hydrogen pump price and perhaps make localised production more economic. Conversely, localised production may actually increase emissions of greenhouse gases if hydrocarbons are used in production processes such as Steam Methane Reforming or if electrolyzers use electricity from non renewable sources. For example CO<sub>2</sub> capture and sequestration is currently being considered as a means to reduce greenhouse gas emissions, this is only practical if the hydrogen is produced centrally and there is long term storage relatively nearby.

This literature review of current research is intended to identify whether these issues have been addressed and where further work is required. There has been a significant amount of research on the end use of hydrogen, particularly the development of fuel cell vehicles, but this is outside the scope of this review which is concerned primarily with the supply chain associated with hydrogen powered vehicles. This review of current research will therefore focus primarily on supply and distribution systems, considering production only where appropriate.

### 4.1 Scope and review method

This section reviews the work of researchers and encompasses research world wide. It is not limited to the UK, because if supply and distribution of hydrogen is a problem, it is likely to be

common problem worldwide. Because of the recent emergence of hydrogen-fuelled vehicles and also the developing nature of research, the review is limited to papers published in English and post 1995.

The review was carried out in two phases, the first phase informed the focus of the research in this thesis, including choice of case studies and modelling techniques. The second phase identified work carried out by researchers subsequent to the formation of the hypothesis. It is important to note the date of these reviews as two papers are of particular relevance and were produced after the initial modelling work was undertaken in this project. These papers are *"Analysis of the cost of a hydrogen infrastructure for buses in London"* (Shayegan S et al., 2006) and *"Determining the lowest cost hydrogen delivery mode"* (Yang C and Ogden J, 2006a). This review treats these two papers separately in section 4.2. It also includes a brief review of the London hydrogen conference in Jan 2010 which usefully focused on what current research is being carried out at UK Universities.

In reviewing existing research publications, it was noted that authors seem to use different measured outcomes to judge the success or failure of various alternative hydrogen systems. This sometimes makes it difficult to draw accurate comparisons. One of the most complete measures used is the "Well To Wheels" (WTW) method. This is a form of fuel life cycle analysis, and in the context of a hydrogen supply and distribution system it refers to the total costs and emissions involved in producing, storing, transporting, and using hydrogen as a fuel. The cost and environmental impact of the manufacture of the vehicles is considered outside the scope of this thesis, as is the environmental impact of production plant equipment manufacture (although costs are included).

### 4.1.1 Production Options

Research into hydrogen production falls into two categories, firstly, studies of current technology, mainly related to plant size, efficiencies etc., and secondly related to the development of new technologies for hydrogen production.

The costs of current production technologies were summarized in the previous chapter, from an industry / technology point of view. This brief section will focus on work by researchers. Thomas, in 1998 identified the cost of delivered hydrogen by plant size and hence number of vehicles. The following table was adapted from this work. The cost in US dollars (\$) are quoted directly from the

paper, the cost in UK £ are corrected to 2008<sup>14</sup> prices. Due to the volatile nature of gas prices this should only be considered as an approximation.

<b>Delivered cost of hydrogen from remote large scale centralized production (includes production, liquefaction, delivery and dispensing)</b>				
	<b>\$/kg</b>	<b>£ / kg</b>	<b>Plant size (t/day)</b>	<b>Number of vehicles</b>
<b>Praxair</b>	3.4	3.77	21.5	41,000
<b>Air Products</b>	3.3	3.66	26.3	50,000
<b>BOC</b>	3.25	3.60	43.9	83,000
<b>Praxair</b>	2.3	2.55	215.4	410,000
<b>Air Products</b>	2.4	2.66	263.5	500,000
<b>Delivered cost of hydrogen from on site production plants at (at refueling station by SMR process)</b>				
	<b>\$/kg</b>	<b>£ / kg</b>	<b>Plant size (t/day)</b>	<b>Number of vehicles</b>
<b>Praxair</b>	2.2	2.44	2.72	5,400
<b>Air Products</b>	3.5	3.88	2.72	5,400
<b>BOC</b>	3.8	4.21	1.36	2,700
<b>Praxair</b>	5	5.54	0.45	900
<b>BOC</b>	11	12.19	0.18	360

**Table 4-1 Cost of hydrogen by plant size**

(Thomas C et al., 1998) adapted from figures 3 & 4. "Number off vehicles" is the number of FCVs that can be supplied with hydrogen of the stated plant capacity

The delivered cost of gaseous hydrogen produced using large scale centralised production was shown in the previous chapter, to be £17.50 per GJ or £2.20 per kg. This compares reasonably well with Thomas' range of £2.66 to £3.77 per kg in Table 4-1 above, given that the research was carried out in 1998. An example of the cost of on site production was shown in the previous chapter to be in the region of £3.53 per kg for plant sizes of 100 kg/day (Shayegan S et al., 2006). The BOC figure above is £12.19 per kg, albeit delivered rather than just at the factory gate as quoted by Shayegan. If both figures are correct, it implies that hydrogen delivery costs are three times the cost of production. If either or both figures are not quite accurate, it highlights the wide variation in cost estimations. It is reasonable to conclude that production costs need to use data as accurately as possible in the modelling to avoid costs skewing the optimum pathways and, for on site production in particular, plant size costs are matched to demand.

Research so far shows that small-scale on site production is more expensive than large scale centralised production. One possible solution to this problem would be the use of factory built units which should benefit from the economies of scale in terms of production and also potentially reduce on site construction costs. This issue was addressed in the paper by Thomas when he estimated that significant savings can be achieved using large volume production (over 100 units) of small

<sup>14</sup> Based on standard conversion rate data (refer to clarifications)

capacity, producing hydrogen for fewer than 100 vehicles. For example, it is estimated that a factory built unit to support a thousand fuel cell vehicles can deliver hydrogen at a third of the cost of an equivalent bespoke unit (Thomas C et al., 1998). He also referred to similar cost savings reported by Joan Ogden<sup>15</sup> and her colleagues at Princeton in support of his research.

A search in the Science Direct database produced almost 200 papers with hydrogen production processes in the title. A significant number (78) of these papers were related to the conventional production technologies of reforming, electrolysis and biomass. Approximately thirty related to the production of hydrogen from renewable energy sources such as wind and solar electricity. There were about forty papers related to high temperature processes, such as thermolysis, typically using nuclear power. The remainder were associated with new and novel technologies, such as fermentation and bacterial processes, much of which involved small scale production. Consequently, further review of these novel technologies are considered to be outside the scope of this thesis.

#### **4.1.2 Storage and Transportation research**

In the previous chapter, storage systems were broken down into static, transportation and on board storage tanks. The issues can be summarised as:-

- Gaseous storage – increasing storage pressures and associated materials technology.
- Liquid storage – improvements to insulation to minimise losses due to boil off.
- Solid storage – developments in materials technology to achieve acceptable storage densities and charging / discharging rates.

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<sup>15</sup> Dr. Joan Ogden is Associate Professor of Environmental Science and Policy at the University of California.



Current typical gaseous hydrogen storage pressures							
Hydrogen in this region tends toward liquid phase							
Temp Deg C	Pressure (Bar)						
	1	10	50	100	300	500	1000
-255	73.28	74.25					
-250	1.12	68.75	73.67				
-225	0.51	5.54	36.62	54.81	75.29		
-200	0.33	3.38	17.66	33.38	62.12	74.26	
-175	0.25	2.48	12.30	23.48	51.20	65.04	
-150	0.20	1.96	9.60	18.36	43.08	57.34	
-125	0.16	1.63	7.92	15.18	37.11	51.09	71.61
-100	0.14	1.39	6.76	12.99	32.61	46.01	66.66
-75	0.12	1.22	5.91	11.38	29.12	41.85	62.32
-50	0.11	1.08	5.25	10.14	26.34	38.38	58.50
-25	0.10	0.97	4.73	9.15	24.06	35.46	55.12
0	0.09	0.88	4.30	8.34	22.15	32.97	52.12
25	0.08	0.81	3.95	7.67	20.54	30.81	49.42
50	0.08	0.75	3.65	7.10	19.15	28.93	47.00
75	0.07	0.69	3.39	6.61	17.94	27.27	44.81
100	0.06	0.65	3.17	6.18	16.88	25.79	42.82
125	0.06	0.61	2.97	5.81	15.94	24.47	41.00

**Table 4-2 Hydrogen fluid density (kg/m3) for given pressure and temperature**  
 Calculated using formulae provided by the hydrogen Analysis Resource Centre  
 (US DOE, 2009)

Table 4-2 shows the typical densities of liquid and gaseous hydrogen storage based on pressure and temperature. In general, liquid hydrogen is stored at cryogenic temperatures and low pressure, shown in blue, whereas gaseous hydrogen is stored at high pressure and ambient temperatures with typical ranges highlighted in yellow. Current static hydrogen storage solutions are acceptable and were discussed in the previous chapter. On board vehicle storage and storage of hydrogen during transportation for delivery is more of an issue. For onboard storage systems total system weight is a more appropriate measure of their suitability as this takes into account both the weight of the fluid and the storage materials. The US DoE use this measure and published data on current a future targets as shown in Figure 4-1.

# Gravimetric Energy Density vs. Volumetric Energy Density of Fuel Cell Hydrogen Storage Systems

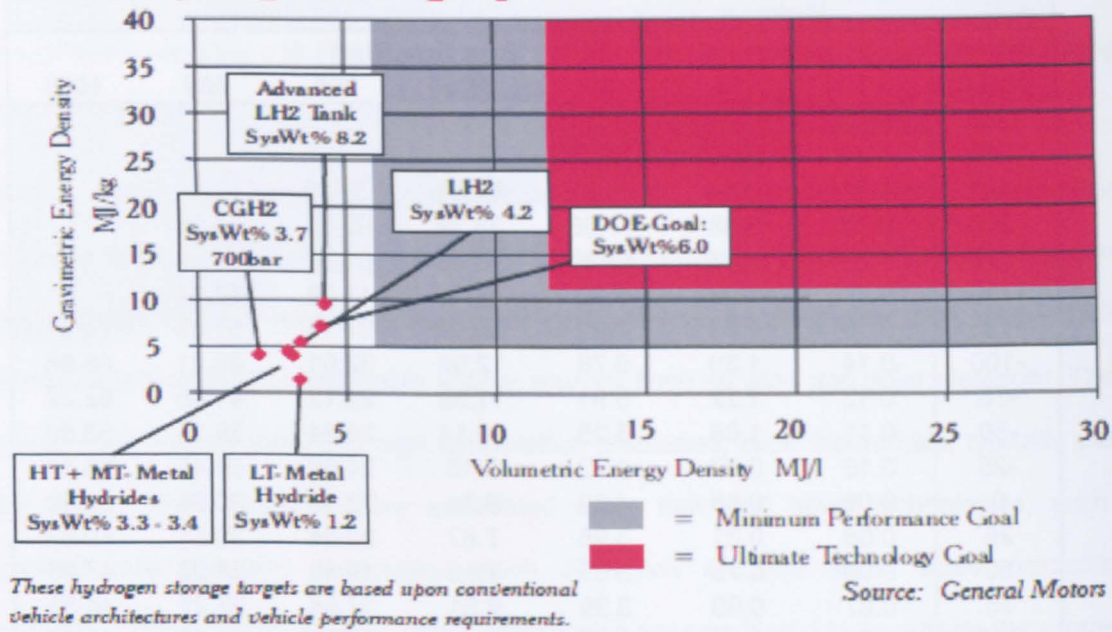


Figure 4-1 Target hydrogen storage system densities (US DoE, 2002)

There are numerous papers written on current research into alternative forms of hydrogen storage; these mostly involve complex analysis of materials and structures. For this reason it was decided to obtain the view of an expert in this field who could present the data in a simple and understandable format. Professor Z Xiao Guo<sup>16</sup> is one such expert who was prepared to share some views on this subject and was interviewed as part of this research in January 2008.

Professor Z Xiao Guo expressed the view that, currently, solid state hydrogen storage is not competitive in terms of cost with more conventional methods of storing hydrogen. However he expressed the view that the issue of cost of hydrogen storage is less likely to be a barrier than the current cost of Proton Exchange Membrane (PEM) fuel cells. The most likely technical challenges are surrounding the issue of the rate at which solid storage systems can be charged and discharged. This is a similar problem to that of current battery technologies. In many ways, solid state hydrogen storage is a competitor to batteries as energy stores and both may play a role in the future.

Professor Guo considered that advances in storage densities could be a driver to change to solid state hydrogen storage for transport. He claimed that current technology is in the region of 6% of fuel to total system weight, which includes the weight of the fuel and storage. When compared

<sup>16</sup> Professor Z Xiao Guo is a staff professor at University College London with specific interests in materials and inorganic chemistry.



other hydrogen storage system densities in Figure 3-3, it is clear that this is the minimum figure at which solid state hydrogen may be competitive with gaseous hydrogen.

In Professor Guo's opinion, it may be that solid state hydrogen storage systems require a completely different distribution system than conventional hydrogen pathways. In the future we may use replaceable on board hydrogen storage cylinders, with regional filling stations distribution centres, much the same as the Calor Gas bottle in use today for heating. In such a scenario, the distribution system is greatly simplified to conventional transport by flat bed lorries. No significant compression or liquefaction is required, with no issues of losses due to cold conservation. Hydrogen may be generated at distribution centres or transported from centralised production facilities by pipeline for refilling of cylinders.

### 4.1.3 Future vehicles

In chapter 2, the current technology of alternative powered vehicles was addressed; it did not however address the issue of the future. Whilst this thesis is focusing on the use of hydrogen, it is useful to review how researchers see the development of the various technologies in the future. For example, if the uptake of hydrogen vehicles proves to be a slow process, the market for factory built hydrogen production units discussed in the previous section is likely to be quite limited. A paper by Tseng in 2005 addressed this issue for a variety of vehicles, forecasting costs forward to years 2015 and 2050 respectively. The table below is a summary of the forecasts from this paper:-

Technology	Efficiency (note 1)		Capital cost (note 2)		Advantage ratio (note3)	
	2015	2050	2015	2050	2015	2050
ICE Vehicle	1.08	1.27	1.00	1.00	1.08	1.27
FC Vehicle (FCV)	2.20	2.90	1.15	1.10	1.91	2.64
Hybrid Gasoline	1.45	1.50	1.03	1.01	1.41	1.49
Hybrid Diesel	1.75	2.00	1.15	1.05	1.52	1.90

Table 4-3 Future vehicle cost forecasts  
(Tseng P et al., 2005, table 3)

- Notes:-
- 1) Efficiency is compared with a base of 1 for ICV in 2005
  - 2) Capital cost is compared with a base of 1 for ICVs in 2005
  - 3) Advantage ratio is efficiency divided by capital cost.

This table indicates that hydrogen FCVs will have an advantage compared to ICVs by the year 2050. Tseng predicts that the capital cost differential should be down to 10% and the efficiency advantage (advantage ratio) will then come to the forefront. But comparison with the forecast for hybrid diesels is not so positive; they are still forecast to be almost 5% more expensive, however

the efficiency advantage is better. What is not so certain is whether the advantage over hybrid diesels will be sufficient to warrant a new infrastructure for hydrogen-powered vehicles.

A paper published by researchers at UCA Davis was slightly less optimistic, forecasting that the cost of FCVs would fall to \$28,500 by 2025. Compared with the base gasoline case at \$23,200, this would give a capital cost ratio of approximately 1.22 using the same criteria in Table 4-3 (Yongling S et al., 2010, Table 13).

Similar research at the Massachusetts Institute of Technology suggests that “market competitive” hydrogen powered FCVs could be available (assuming a significant hydrogen supply infrastructure in place) by 2030 (Schäfer et al., 2006). In this case the conclusions are slightly more optimistic than Table 4-3. They also made some interesting comparisons between costs, emissions and energy usage between a base reference case and the year 2020 see Figure 4-2 below.

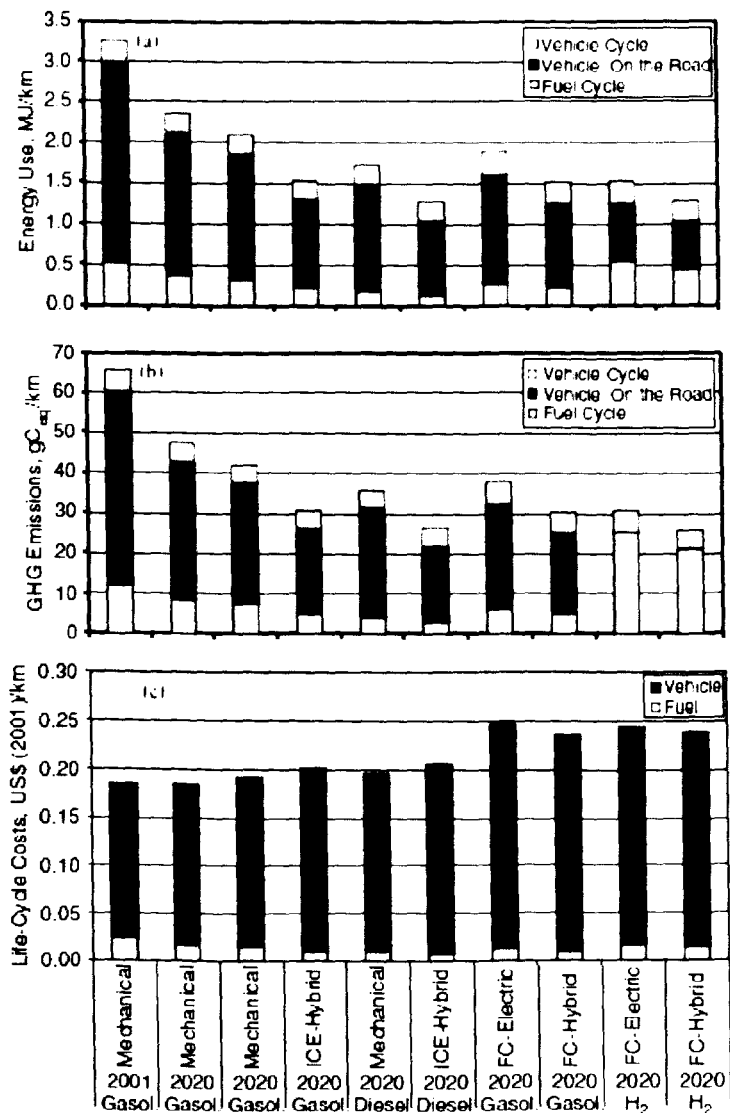


Figure 4-2 Comparisons of vehicles costs, emissions and energy usage  
(Schäfer et al., 2006, Fig 3)

There are two major obstacles to hydrogen vehicles powered by Proton Exchange Membrane (PEM) fuel cells. Firstly the current costs of PEMs, and secondly, concerns over the amount of platinum needed for millions of FCVs. At present, PEMs are significantly more expensive than ICVs and cost estimate forecasts seem to vary widely. In 2003 a typical cost of \$225 / kW was predicted for high volume production (>0.5 million units per annum) (Rose R, 2003). However this is still a long way from the industry's target of between \$30 and \$50 per kW. This is the cost target for PEMs to become competitive with the cost of high volume ICEs.

A paper in 2009 in Transport Reviews appears to concur with the results in Table 4-3 with respect to the cost of hydrogen vehicles. Depending on vehicle type, most forecasts show hydrogen FCVs as being slightly cheaper than convention ICEs (Jokisch S and Mennele T, 2009).

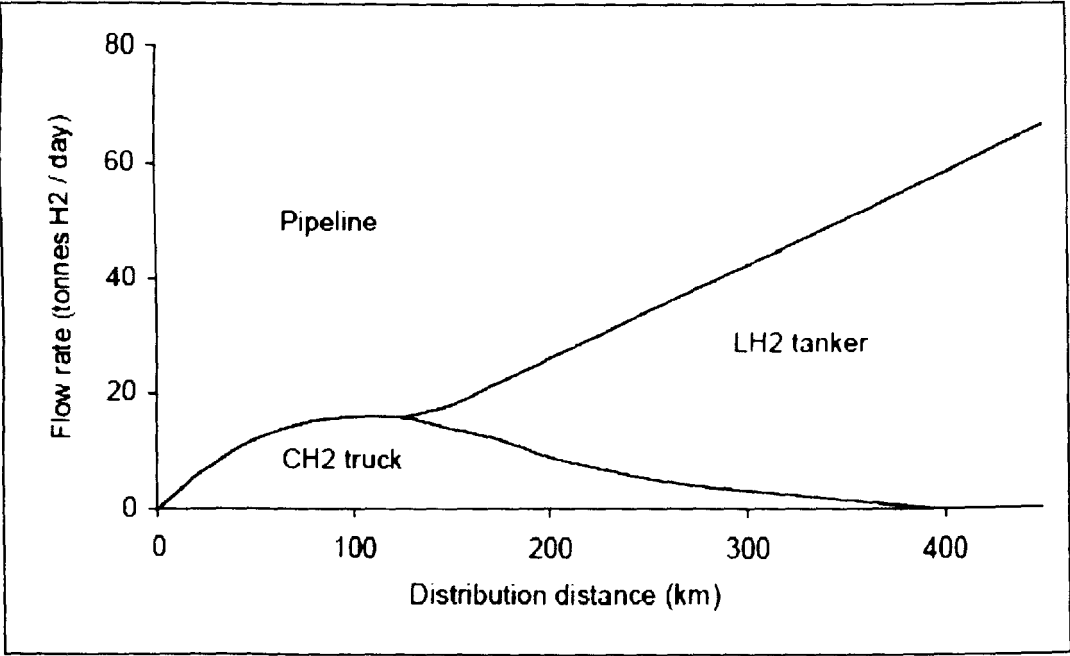
#### **4.1.4 Modelling methods**

This literature review now provides an overview of modeling techniques and summary of conclusions used by others to address the same or similar research issues addressed in this thesis. However it is not intended to be a critical analysis of the suitability of the modeling techniques chosen by others. The proposed method of modelling different pathways in this thesis is a relatively simple, single point model based on Excel spreadsheets. Should any of the modeling techniques reviewed here, be deemed to be beneficial in this thesis, they will be addressed further in later chapters.

A commonly referred to model is the MARKet ALlocation model (MARKAL), a dynamic linear programming simulation model. It is used to portray the entire energy system. Further details can be found in a working paper on modelling hydrogen systems in the UK and other countries (Joffe D et al., 2007). Whilst the model in the paper considers distribution systems based on demand and distance, it does not appear to model "on site production". It takes the hydrogen distribution systems identified in the paper by Yang and Ogden (Yang C and Ogden J, 2006b) which is discussed in more detail later. Whilst this is a very powerful modelling technique, it does not appear to be applicable for on site production pathways, which is one requirement for this project.

The issue of modelling hydrogen pathways is addressed further in another paper by Joffe titled "Review of modelling approaches to the development of a hydrogen economy" (Joffe D and Strachan N, 2007). This paper compares several modelling techniques as well as categorising modelling approaches. It discusses the spatial dimension of hydrogen infrastructures, identifying that, apart from demand and supply chain length, geographic location is important. It notes that

pipeline modelling costs are particularly susceptible to terrain variations. For example, he uses a diagram by Yang and Ogden (Figure 4-3), which shows the least cost option, based on demand and supply chain distance for three types of supply system (gaseous and liquid hydrogen by truck and gaseous hydrogen by pipeline). If spatial considerations were taken into account, this figure could only be applicable for a fixed set up conditions (city, urban, rural etc.).



**Figure 4-3 Least cost hydrogen distribution method as a function of flow rate and distance**  
(Joffe D and Strachan N, 2007)

Joffe also refers to “resource competition” whereby one should consider whether a better use could be made of energy, such as renewable electricity etc. Whilst this is a valid point, it further complicates any modelling. Given that we need hydrogen for transport in addition to current production, it may not be too simplistic to exclude resource competition at the early stages of modelling systems. This may not actually be an issue until there is a significant uptake of hydrogen powered vehicles.

One specific paper related to modelling is worthy of mention as it is based on the same CUTE project as the modelling inputs utilised in this thesis. The paper is titled - “Modelling of a hydrogen infrastructure for vehicle refuelling in London” (Joffe D et al., 2004). The main difference is that unlike the simple single point model, this paper investigates “*how an infrastructure for refuelling buses and fleet vehicles might develop in London*”. The model uses a nodal network structure to define “*infrastructure as a collection of technologies that are connected together in a specific way*”.

It also categorises these technologies, which seems to be a good approach for a single point model. Joffe identifies them as:-

- *Sources of energy*
- *Conversion (including compression)*
- *Fuel transportation*
- *Storage*
- *Demand*

Another complex dynamic model uses Mixed Integer Linear Programming (MILP) which is used to support BP's strategic H<sub>2</sub> infrastructure planning using Well to Wheel (WTW) analysis (Hugo A et al., 2005). This model mainly looks at the strategic planning level. It does consider a wide range of paths but concludes *"that for hydrogen to succeed as a fuel of a sustainable future, a commitment is required to create an entirely new fuelling infrastructure"* and that *"any investment strategy for building up a hydrogen supply chain needs to be supported by rigorous quantitative analysis that takes into account all the possible alternatives"*. This is consistent with the widely held view that in the short term, a hydrogen economy is unlikely to be based on economic justification.

During this overview of modelling techniques, little evidence has been found of a simple model which analyses pathways for a single supply system. The nearest research relevant in terms of modelling was found to be in papers by two research teams at Imperial College London and UC Davis (California). Whilst both consider networks, they consider hydrogen supply based on demand rather than timescale; this removes the difficulties of forecasting uptake into an unpredictable future.

## **4.2 Key recent Research papers (2007)**

The research in this thesis covers an emerging topic. Consequently, it is not surprising that significant new work has evolved whilst this PhD project was underway. The publication of two papers in particular, focus on a hydrogen supply chain for fleet vehicles, and take an approach very similar to the original hypothesis of this research. Both research papers investigated supply chain networks for a typical city, such as London (Shayegan S et al., 2006) and numerous cities in the United States (Yang C and Ogden J, 2006b). Considering the dates of publication it would appear that these were independent studies carried out in parallel. They do have some degree of common referencing of researchers, such as Dr. Joan Ogden, which is perhaps, not surprising given the fairly limited numbers of people who have been studying hydrogen pathways for any length of time.

According to Yang *"There are a number of barriers that must be overcome before hydrogen can be widely used as transport fuel. One of the most important is the current lack of hydrogen*



*infrastructure*". Whilst Shayegan comments *"This increased interest and investment has been stimulated by a perceived need to replace fossil fuels for environmental and / or security of supply reasons"*, this is consistent with the reasons for change explored in Chapter 1.

It is interesting to note that both of these studies focused on city wide distributions rather than a region such as a county. This was possibly to ensure maximum population densities and to limit the length of the supply chain. In the case of Yang and Ogden they also focused on a single point of use supply chain. Both papers use simplified models. For the London study, two Excel based models were used, one for onsite production and another for offsite production. For the U.S study, a simplified idealised model for a single point of use supply chain and another distribution model for networks.

Yang appears to consider only the supply chain downstream from the point of production, whereas Shayegan also considers a limited number of production options. Both consider liquid and gaseous hydrogen options by road tankers and pipelines where appropriate. Neither paper seemed to consider any novel production technologies or the use of solid state hydrogen storage and delivery. This is not surprising considering the limited realistic data available to model, but developments in solid state hydrogen storage could affect the conclusions reached in these papers.

Both models break down the delivery systems into stages, taking into account capital and operating costs, likely demand scenarios and supply chain lengths. A brief summary of the pertinent points from the two papers are:

- Yang seems to presuppose that centralised production is the logical option. This does not allow comparisons to be drawn between centralised and localised production. By way of contrast, Shayegan includes both centralised and localised production, but it is limited to steam methane reforming and electrolysis.
- Shayegan includes land costs, which is appropriate when considering a specific city such as London (the focus of her research). But it would skew any generic city comparisons, as not all city land costs are equal. One could argue that land costs could be ignored for generic modelling but they should perhaps be added for modelling of specific pathways, since land costs for specific areas are well known. Land value generally increases in value over time, and could perhaps be considered a net asset on any balance sheet.
- Both include some network and distribution modelling based on fuel demand and distance. Whilst this is possibly necessary for any future city wide planning, it does complicate the

analysis of results as shown in Yang's paper, figures 12, 13 and 14. An alternative approach might be to model the best single point to point scenarios and if perhaps localised production can be shown to have an advantage then the network modelling becomes unnecessary.

These papers conclude that the ideal solution varies according to demand (flow rates) and distance. Yang recognises the need to consider alternative centralised production as well as localised production in any future analysis, which would bring the analysis of the two papers more into line with each other in terms of research topics. Shayegan identified a need to consider alternative costs of hydrogen production and energy price variations. These factors should be included in any modelling work in this research.

A more simple approach may have been to first identify the viable single point to point supply chains. This would enable more detailed analysis of variations based on demand / distance and energy variations. Results might exclude all but a few pathways, and then distribution network analysis could be carried out on a city by city basis factoring in specifics such as population densities, fleet sizes and types with only a few chosen pathways to model. Modelling work in this research is focused on the first part of this potential approach.

In 2009 Shayegan published a further paper titled *"Hydrogen for buses in London: A scenario analysis of changes over time in refuelling infrastructure costs"* (Shayegan S et al., 2009). Although this paper considers a transition over time (2007 to 2025), there were a number of interesting points and conclusions made. The pathways chosen were similar to the previous papers reviewed in this section, typically, production by SMR or Electrolysis and transporting in liquid and gaseous state. The first key point is that she claims *"in the fifth pathway, CH<sub>2</sub> (compressed hydrogen) transportation by road is only possible for flow rates below 3.5 t/d, because of practical considerations such as loading and unloading time"*. This is an interesting point as most other researchers seem to only consider cost of delivery, although of course this is in effect what Shayegan alludes to. The figure of 3.5 t/d is presumably a practical upper limit which is dependent on delivery chain length considering delivery times and allowance for loading / unloading etc. It is an important point at which researchers may have to exclude this pathway for large scale uptake of hydrogen delivery by road in gaseous state.

The costs of hydrogen are reported in £/kg over the 18 year period considered. Unit costs generally decrease, but start from a relatively high base. The five pathway delivery costs vary according to the scenarios in the paper, but can generally be reported in order of decreasing cost as:-

- 1) Off site pipeline delivery (most expensive)
- 2) Off site liquid hydrogen delivery by road
- 3) Off site gaseous hydrogen delivery by road (with demand limitations)
- 4) On site electrolysis
- 5) On site SMR (least expensive)

### 4.3 The London Hydrogen conference (2010)

At a t H<sub>2</sub> LTN conference in London on 20<sup>th</sup> January 2010, there was an opportunity for some UK academic institutions to present their current areas of academic interest. It was a useful measure of current hydrogen research relevant to this thesis topic. The research areas are summarised in Table 4- 4:-

	Kingston University	UCL	Brunel university of West London	University of East Anglia	City University	University of Surrey	University of Southampton	University of Birmingham	Imperial college
Hydrogen production		x						x	
Energy generation Fuel cells						x			
Energy storage – Electricity							x		
Energy storage - Hydrogen metal hydrides				x				x	
Energy storage – Hydrogen nano-technology			x				x		
Energy storage systems					x				
Hydrogen safety	x								
Vehicles BEVs and FCVs									x
Hydrogen re-fuelling infrastructure									x

Table 4- 4 Summary UK academic research based on the London hydrogen conference report (LT Network, 2010)

It would appear that most interest by the universities attending the conference is being focused on energy storage for both hydrogen and electricity. Electricity storage is mainly focused on super capacitors and battery storage using new materials such as Lithium and Redox flow technology. Hydrogen storage research is focused on solid storage systems such as metal hydrides and nano-tubes. This would be expected as solid state hydrogen storage of hydrogen is a more recent

concept compared with the older, more mature storage technologies of storing hydrogen in the gaseous and liquid state. The University of East Anglia is carrying out research into hydrogen storage using metal hydrides. In the poster, it is claimed that storage capacities of 7.6 wt% is achieved but acknowledges limitations of "slow kinetics". This is consistent with the views of professor Guo earlier in section 4.1.2.

There is some interest at UCL and the University of Birmingham in hydrogen production. This appears to be split between improving existing technologies, such as membrane systems and electrolyzers, and newer technologies such as bio-manufacture of hydrogen using technology such as dark fermentation. At City University in London, research is being carried out into off grid renewable energy storage systems, using hydrogen. The flow diagram suggests an installation very similar to an earlier project carried out at West Beacon farm; named HaRi and which is reviewed in detail in chapter 5 (refer to Figure 5-7).

The research work at Imperial College London appears to be the most relevant to this research topic. The two areas in the poster related to the use of BEVs and FCVs and modelling of a hydrogen refuelling infrastructure. A review of the analysis of a hydrogen re-fuelling infrastructure seems to be referring to the work by Joffe already reviewed in this chapter, as a review of recent work at Imperial did not highlight any new publications on this subject.

The research comparing between BEVs and FCVs is an interesting topic and is an example of how research has evolved. Original comparisons for hydrogen vehicles tended to be with conventional Internal Combustion Engine vehicles (ICEs). The comparison is now with Battery Electric Vehicles (BEVs). The issue of energy storage is seen by many as the main technology obstacle to be overcome before either vehicle can replace the conventional ICE. It is recognised that the low energy density of batteries is a "significant challenge" with energy storage for *"200km range requiring roughly 150kg of lithium ion cells or more than 500kg of lead acid batteries"* (Offer G et al., 2010)

Although universities appear to recognise the potential for hydrogen and the obstacles of storage, it would seem that apart from the possible exception of Imperial, very few UK universities are carrying out significant research into how a hydrogen supply and distribution system may evolve to support the transition to hydrogen vehicles. This is consistent with the original hypothesis of this research in Chapter 1, which suggested that research into hydrogen distribution systems tended to lag behind other areas in this field. The conference was also attended by representatives of

industrial companies interested in the field of hydrogen for transportation purposes such as Air Products, BOC and BP, but this review of the conference is limited to research by academic institutions.

## 4.4 Summary of literature reviews

Chapters 3 and 4 have focused on hydrogen from both a technologist's and researcher's point of view. It is useful to consider the period of time in which this research has been taken place, in particular, issues related to the transportation of hydrogen. During the period 2003 to date, crude oil prices have more than tripled with the consequential increases in the price of natural gas and electricity. The term "energy security" has emerged, largely due to terrorism and instability in the regions containing major oil and gas reserves. Global warming, although well established as an issue by 2003, is now even more on the world political stage. The popularity of Bio-diesel as an alternative fuel has risen, and perhaps waned due to land and food resource issues. Electric battery powered vehicles have started to reach the market, although still in small numbers and can be very expensive. Hydrogen demonstration vehicles have emerged as one technological fix for transport's environmental conundrum, with hydrogen powered fuel cell fleet vehicles being successfully demonstrated in the CUTE and ECTOS projects. There has been some progress with more efficient diesel engines but at the time of writing no single technology break through.

Four groupings of potential options have been identified so far for vehicles:-

1. The hydrocarbons – such as diesel, LPG, CNG
2. The hybrids – which for the purposes of this research is defined as a combination of hydrocarbon powered ICE and battery powered electric motors.
3. The alternative fuel vehicles – for example diesel vehicles running on bio-fuels
4. The alternative technology vehicles
  - 4.1. Battery powered electric vehicles.
  - 4.2. Hydrogen powered Fuel cell vehicles.
  - 4.3. Hydrogen dual fuel vehicles which use both hydrogen and other hydrocarbons in an ICE
  - 4.4. Hydrogen hybrid vehicles which use an electric motor for the power unit but may have a combination of hydrogen (via a fuel cell) and electricity (via a battery) as on board energy storage.

Of these options, 1 and 2 rely on the existing hydrocarbon distribution system. Option 3 can also rely on the same system, albeit with a different production technology. Only option 4 requires a change to the distribution system. However, the battery powered option has an existing system in place, in the form of the national grid, as electricity supply is available across the UK. This could be

an example of the resource competition that Joffe refers to (Joffe D and Strachan N, 2007). Modelling of such a system would need to consider costs associated with upgrading the existing grid, for widespread use of electric vehicles. Hydrogen is unique in that a completely new supply and distribution system would be required; however in this instance "uniqueness" is a clear disadvantage. It has been shown earlier that the existing system could not even cope with a modest uptake of hydrogen vehicle usage. If distribution systems alone were considered, hydrogen would appear to be the least preferred option.

Hydrogen costs have been evaluated in this review and at first they seem to be reasonably competitive with oil at today's prices, until the cost of hydrogen distribution is taken into account. If hydrogen is not competitive on cost alone, it may need to offer substantial environmental benefits. Either way, it is imperative that the cost of the hydrogen supply and distribution system is kept to a minimum.

Although both hydrogen and battery powered vehicles are referred to as new technologies, in chapter 1, it was shown that hydrogen fuel cells and battery powered electric vehicles are not exactly new, with hydrogen ICEs being more than two hundred years old, hydrogen fuel cells almost as old and battery powered vehicles one hundred years old. The common obstacle to these technologies is the onboard storage and charging systems to enable the vehicles to be used effectively ie: to travel reasonable distances between refuelling. In the case of electricity which already has an "energy distribution system" in the form of the National Grid, it is the cost, charging rate and energy density of the batteries. In the case of hydrogen, there is no significant supply and distribution system and neither does there seem to be one preferred option for on board storage of the hydrogen.

Whilst there are obstacles to hydrogen, these do not appear to be insurmountable. Hydrogen production costs are best addressed by the hydrogen producers in terms of large centralised production. Onsite production and technology could be considered to fall within the supply and distribution category, and needs to be considered. Hence the review of research into factory built production units. Novel hydrogen storage technologies could have a role to play, but their viability and costs are presently unclear.

In his paper entitled "affordable hydrogen supply pathways for fuel cell vehicles" Thomas stated that *"we conclude that the two potential barriers to a viable direct hydrogen fuel cell market – on board hydrogen storage and the hydrogen infrastructure, could be overcome"* (Thomas C et al.,



1998). Although this paper is over ten years old, this statement is still valid and the barriers have not yet been overcome. Hence the issue of infrastructure remains worthy of further research. If one considers fleet vehicles at this stage, the issue of on board storage is lessened due to the fact that vehicles such as buses have more space available for storage and there is a reduced need for a hydrogen supply and delivery system as re-fuelling can be carried out at bus depots. So it would seem that buses could be a suitable starting point for a transition to hydrogen for vehicles. Both BEVs and hydrogen FCVs are “zero emissions at the point of use”, but this is only the downstream element of the complete supply and distribution system. The upstream element, which includes electricity generation and hydrogen production, may produce significant quantities of carbon dioxide, depending on the processes used. During modelling in chapter 8, it will be necessary to make allowance for the method of electricity generation with regard to both cost and emissions as well as the hydrogen production processes.

It is for these reasons that the research is focusing on the supply and distribution system. However it is not practical to study the supply and distribution system in isolation. Hydrogen production needs to be considered due to issues that affect the distribution system (eg: liquefaction). For this reason, modelling needs to be reasonably accurate for production costs. Whilst the boundary of the model could stop at the price of delivered hydrogen, this would not take into account the higher energy value of hydrogen or the greater efficiency of fuel cell vehicles, so a simplified model of end use is appropriate. Also, it is useful to have a baseline comparison, which in this case is logically an equivalent diesel powered vehicle. The most meaningful measure is the cost in monetary terms and emissions per vehicle kilometre travelled and hence another reason consider the end use.

However this apparent simple conclusion requires qualification. Hugo stated that *“Most advocates agree that there is no single supply chain solution template for investing in a hydrogen infrastructure. Instead, it is necessary to have a generic framework that can analyze and compare the performance of the various integrated pathway options on a consistent basis”* (Hugo A et al., 2005). This could be interpreted to mean that there is no “one size fits all solution” and that whilst modelling of complete networks are useful and eventually a necessary exercise, we are not yet at that stage in the hydrogen economy and there is a place for single point simple models that model the spatial requirements of individual situations. Such a model would typically be used for fleet vehicles which perhaps have the simplest distribution network requirements.

## **CHAPTER 5 R&D PROJECTS AND CASE STUDIES**

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Having reviewed the current status of hydrogen production, distribution and use with respect to technology and research, it is now appropriate to review demonstration projects which may be relevant to this research. Research and modelling of distribution systems are an essential part of developing the most appropriate future hydrogen based vehicle supply chain. Such possible supply chains can only be developed and tested in demonstration or pilot projects, and provide feedback on where theoretical predictions differ to actual results and identify areas where further research is required.

This review includes demonstration projects which were either active or planned between 2004 and 2006. The aim was to identify projects which had a "hydrogen" element associated with transportation, which may be relevant to testing of the modelling planned in this thesis. It was originally intended to focus on London and the South East, as an area of relatively high population density and hence suitable for a hydrogen infrastructure requiring a relatively short supply chain length. It was also hoped that there would be a significant number of projects available for review. The review had to be widened to encompass the rest of the UK, due to the limited number of suitable projects. It was relatively comprehensive of UK projects at that time, albeit somewhat restrictive in the number of suitable projects.

One project of particular relevance was Clean Urban Transport for Europe (CUTE), which was both the most relevant and largest scale demonstration project identified in this review. The original intention was to study only the London aspect of this project, but it soon became clear that to do so would ignore the large amount of data available in the project reports. Since all the CUTE demonstration projects involved cities, it was concluded that it would be reasonable to expand the review of the CUTE project to include all the trial cities. This project ended in 2006. A review of final reports and lessons learnt are included. Some of the data from these reports have been used in the modelling later in this thesis.

## 5.1 Clean Urban Transport for Europe (CUTE)

CUTE was a European Union funded trial of hydrogen powered buses in nine European cities. The timescale for the project spanned the years 2001 to 2006, when planning and final assessments were taken into account. The actual operational period of the buses ran for two years from November 2003. A total of 27 buses were used (3 per city) in Amsterdam, Barcelona, Hamburg, London, Luxembourg, Madrid, Porto, Stockholm and Stuttgart (Binder M and Faltenbacher M, 2006, p3). The aim was to test the feasibility of using the buses in a "real environment", to see how the buses performed (technology), to advertise the possible use of hydrogen as an alternative fuel (public perception), and to see what sort of supply chain (infrastructure) was needed. In addition, the costs, reliability and safety elements of the trial were measured and evaluated.

In all, the buses travelled nearly a million kilometres and carried four million passengers (CUTE, 2006, p5), by far the largest scale demonstration project for hydrogen as a transport energy source in the world at that time. Although centrally funded, each city had separate partners for specific elements of the project such as transport operators, hydrogen suppliers etc. However, the buses were supplied and maintained by one supplier. The type of infrastructure and supply chain varied from city to city.

The project produced a number of reports, some of which were restricted in circulation. This review focuses on the public reports relevant to this thesis (see Table 5-1). Specifically the CUTE detailed summary of achievements (CUTE, 2006) and the deliverable number 6, the economic analysis of the hydrogen infrastructure (Binder M and Faltenbacher M, 2006). Data used in this review of the CUTE project is generally sourced from either of these reports.

Summary of deliverables produced			
Deliverable	Title	Circulation	Reviewed
-	CUTE detailed summary of achievements	Public	Yes
1	Hydrogen infrastructure	Restricted	No
2	Operation of Fuel Cell buses	Restricted	No
3	Quality and safety	Public	No
4	Training and Education	Public	No
5	Dissemination activities	Restricted	No
6	Economic analysis of Hydrogen infrastructure	Public	Yes
7	Dissemination	Public	No
8	Final report – Executive summary	Public	Yes
	Final Report - Report	Confidential	No
9	Admission of systems components	Restricted	No

**Table 5-1 CUTE reports**  
Reports are available from - [www.fuel-cell-bus-club.com](http://www.fuel-cell-bus-club.com).

### 5.1.1 The Fuel Cell buses

The buses were based on the Mercedes-Benz Citaro 12 metre series model, adapted to be driven by a Fuel Cell and an electric motor rather than a conventional diesel internal combustion engine. The drive train was the HY-205 P5-1 fifth generation heavy duty drive train developed by Ballard of Canada (CUTE, 2006, p49). The main visual difference to the diesel Citaro bus is the auxiliary equipment mounted on the roof of the bus. Figure 5-1 shows some of the auxiliary equipment required to power a fuel cell bus. The Fuel Cell units which are required to convert the hydrogen to electricity are shown in the background, and cooling fans which are required to dissipate excess heat generated during the process are shown in the foreground. For further explanation of how the fuel cells work, refer to chapter 2.



**Figure 5-1 Roof mounted Fuel Cell bus auxiliaries**

All buses stored the hydrogen on board in gaseous form, with a capacity of approximately 44kg of Hydrogen at up to 350 bar g. However, the minimum supply pressure of the Fuel Cell is 10 bar g (CUTE, 2006, p57), so not all the hydrogen is useable. Although each city had the same number of buses, the operating conditions varied considerably in terms of operating temperatures, traffic density and terrain (see Table 5- 2).

	% availability	km driven by the buses	Operating hours per day	Fuel consumption kg / 100km
Amsterdam	85	109,000	5.61	21.6
Barcelona	60	38,000	3.34	27.4
Hamburg	78	104,000	6.82	20.4
London	88	100,000	7.95	23.9
Luxembourg	80	142,000	9.27	20.9
Madrid	80	87,000	8.86	28.8
Porto	80	47,000	5.23	31.5
Stockholm	90	92,000	8.82	26.6
Stuttgart	100	129,000	8.55	22.1

**Table 5- 2 Bus operating and performance data**  
(CUTE, 2006, p66-67)

Whilst the bus availability (typically 80%) and operating hours (typically < 9 hours) were less than normal for a bus fleet, this trial managed to show that Fuel Cell buses can operate in a city



environment. The fuel consumption figures averaged 24.8 kg / 100km, however there was a significant difference between the best (Hamburg) at 20.4 kg / 100km and the worst (Porto) at 31.5 kg / 100km.

Refuelling target time was under 30 minutes. It was quite a complicated procedure as the buses always came back with some residual hydrogen and complex algorithms were required to make sure that the cylinders were filled to the equivalent of 350 bar g of hydrogen. This was because there was always some residual hydrogen in the tank, which needed to be taken into account, and that filling pressures were dependent on the difference between the filling and operating temperature<sup>17</sup>.. Of the numerous ways that hydrogen can be produced, stored and transported, CUTE only used four different production methods in the demonstration projects:-

- On site Electrolysis – Amsterdam, Barcelona, Hamburg and Stockholm
- On site Steam Methane Reforming – Madrid and Stuttgart
- Off site production trucked in as liquid – London
- Off site production trucked in as gas – Luxembourg and Porto

Initially, London used gaseous hydrogen from a nearby production plant. Madrid also trucked in some hydrogen produced off site. Whilst the technology suppliers varied from site to site, the production capacities were, but storage capacities varied. London had by far the largest capacity at 3200kg, which is logical considering liquid hydrogen was used, the storage capacity roughly equates to one road tanker full of hydrogen. In general, off site production requires greater storage capacities and this is borne out with Luxembourg at 500kg. Other systems varied between 95 and 500kg of hydrogen (CUTE, 2006, p17). There seems to be no correlation between storage and the type of hydrogen production plants. Electrolysers can more easily be started and stopped than Steam Methane Reformers, but this does not appear to be taken into account in storage capacities. Logically electrolysis should be able to run with smaller storage capacity.. Although Steam Methane Reformers, are capable of operating under turndown conditions, the plants are more complicated to start than electrolysers, so it is important that SMR systems have sufficient storage capacity to avoid having to vent surplus hydrogen or avoid regular stopping and starting.

The following sections briefly reviews key points of the pathways used in the CUTE project. As the basic technology has already been reviewed earlier, this review focuses upon the economic and environmental issues associated with each pathway.

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<sup>17</sup> If filled to 350 bar g at a lower temperature than operating, the gas would expand at ambient conditions and hence over pressure the cylinders, hence the reason for algorithms to correct for this.

### 5.1.1.1 On site Electrolysis



Figure 5-2 Hydrogen from electrolysis - Amsterdam  
(Fuel-Cell-bus-club, 2009a)

The electrolyzers that provided hydrogen to the cities of Amsterdam, Barcelona, Hamburg and Stockholm had a capacity of  $60 \text{ Nm}^3/\text{hr}$  (approx.  $5.5 \text{ kg/hr}$ ), which delivered hydrogen at a pressure of  $10 \text{ bar g}$ . The electrolyser was rated at  $400 \text{ kW}$ . It used about  $4.8 \text{ kWh}$  of electricity and  $1 \text{ litre}$  of water per  $\text{Nm}^3$  of hydrogen produced (CUTE, 2006, p25). Based on the figures in Table 5-2 (range of  $21.6$  to  $31.5 \text{ kg} / 100\text{km}$ ), this size of plant would be capable of producing enough hydrogen for the three buses to be driven between  $420$  and  $600 \text{ km}$  per day if operated continuously (about  $140$  to  $200 \text{ km}$  per bus per day).

The environmental impact of the electrolysis process is entirely dependent on the source of electricity. Amsterdam, Hamburg and Stockholm used certified "green electricity". Barcelona used a mixture of on site generation using photo-voltaic cells and the national grid as back-up (CUTE, 2006, p25).

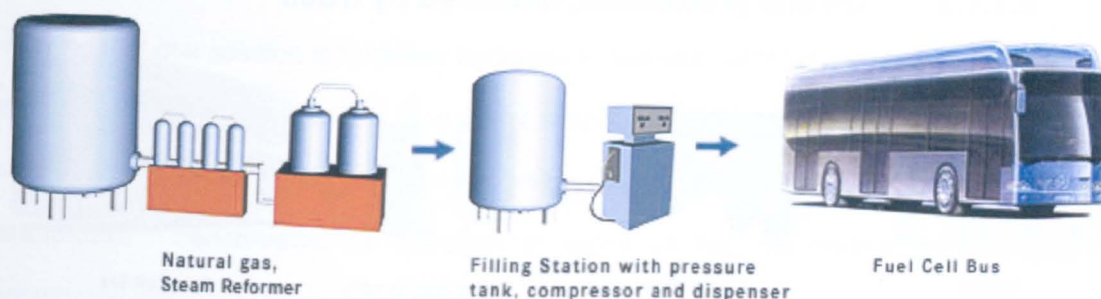
It would appear that the electrolyser supply was matched reasonably closely to the bus demand for hydrogen. With availability<sup>18</sup> figures of  $>98\%$  for three of the cities and  $>90\%$  in the case of Stockholm, it seems that both the choice of plant and selected capacity were well suited for this type of application. This was particularly so as they produced the hydrogen at the purities required

<sup>18</sup> Availability is defined as the % of time that the plant is available to produce hydrogen after planned maintenance and unplanned stoppages have been deducted.



to meet the bus fuel specification and capable of turndown<sup>19</sup> to 25%, if reduced production rates were required (CUTE, 2006, p25).

#### 5.1.1.2 On site Steam Methane Reforming (SMR)



**Figure 5-3 Hydrogen from Steam Methane Reforming - Stuttgart (Fuel-Cell-bus-club, 2009d)**

Steam Methane Reformers were used in the cities of Madrid and Stuttgart, two plant sizes were used, with a capacity of 50 Nm<sup>3</sup>/hr (4.5 kg/hr) and 100 Nm<sup>3</sup>/hr (9 kg/hr) respectively. Hydrogen delivery pressure was 15 bar g. Further purification was required to achieve purities required for use in a fuel cell by a pressure swing adsorption unit (PSA). The plants used about 5.5 Nm<sup>3</sup> of natural gas per kg of hydrogen produced (CUTE, 2006, p28). The capacity of the SMR in Madrid is slightly smaller than the electrolyzers and would produce enough hydrogen for the three buses to travel about 410 km per day if operated continuously (about 136km per bus). Stuttgart, having a plant twice the size would theoretically double the bus ranges.

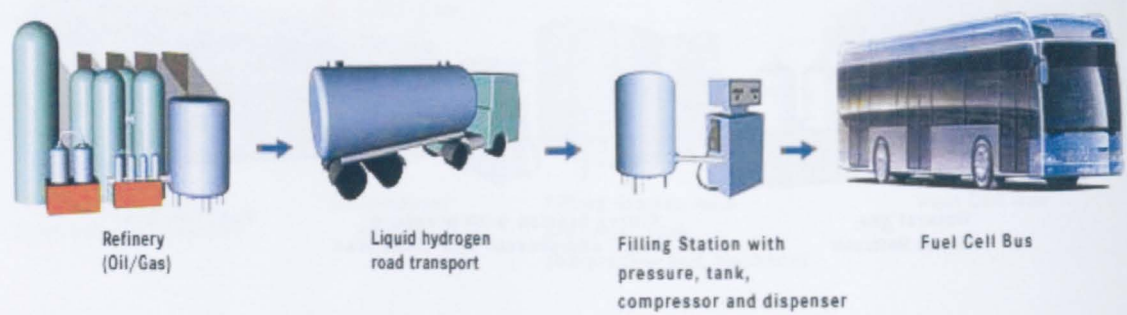
- (3) Unlike the electrolysis process, which has little environmental impact, the flue gas from the reformer can produce significant amounts of carbon dioxide. The flue gas specification in the CUTE project was defined as less than 25% CO<sub>2</sub> and 0.01% hydrocarbons (CUTE, 2006, p28). The project appears to have maximised the efficiency of the process using technology such as recuperative burners.

Even with the use of the tail gas being used to provide the heat for the burners, this type of process will always produce significant quantities of greenhouse gases such as carbon dioxide. One alternative would be carbon capture and sequestration, where the carbon dioxide is separated and then stored permanently, but this is not suitable for localised or on site production.

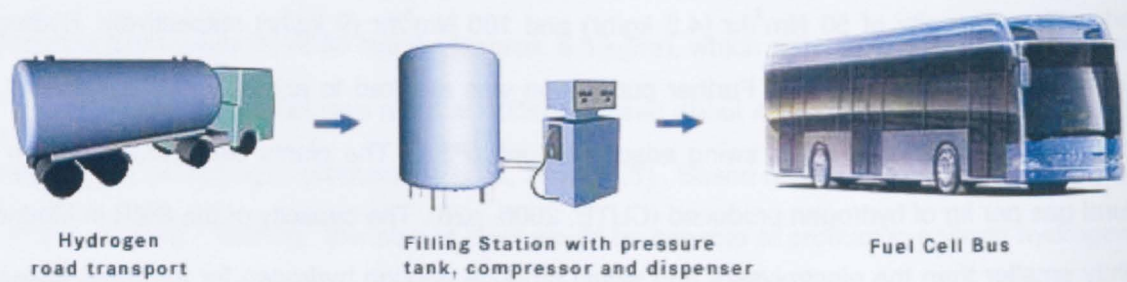
<sup>19</sup> Turndown defines the degree to which output can be reduced and still produce hydrogen ie: output / capacity.

Although these plants have been built to a modular design with automatic start up and shutdown, they operate more efficiently if allowed to run continuously with little or no turndown. Matching of supply and demand or significant storage capacity is required to achieve this.

**5.1.1.3 Off site production, delivered by truck**



**Figure 5-4 Truck delivered liquid hydrogen - London (Fuel-Cell-bus-club, 2009b)**



**Figure 5-5 Hydrogen from Steam Methane Reforming – Luxembourg and Porto (Fuel-Cell-bus-club, 2009c)**

Externally produced hydrogen from centralised production facilities were used in the cities of London, Luxembourg and Porto. This can be further subdivided into Liquid hydrogen in the case of London (Figure 5-4) and gaseous for the other two cities (Figure 5-5). The key differences in the trucked in pathways was the liquefaction of the hydrogen before transportation and the additional carrying capacity of liquid hydrogen trucks when compared with gaseous hydrogen.

The environmental impact is dependent on the production technology used and also the added impact of the emissions from the delivery trucks themselves, due to the significantly reduced carrying capacity of hydrogen tankers compared with diesel tankers, although the CUTE reports do not appear to address this issue.

For gaseous hydrogen, the need to match supply to demand is not such an issue. Gaseous hydrogen can be stored in high pressure cylinders indefinitely (subject to zero leakage) if demand



is relatively low. For high demand, the main issue would be the increase in deliveries required. One tanker delivery per week could provide enough hydrogen for only two buses<sup>20</sup>. For liquid hydrogen, the need to match supply to demand is very important due to the potential for losses due to boil off if liquid hydrogen is stored for long periods, as occurred in London.

It may be that one solution is to deliver hydrogen in gaseous state for low demands and liquid state for high demands. However this is a slight simplification as it does not take into account the delivery distance. This is the approach taken by Yang, when he states that “we characterize the point-to-point transmission of hydrogen in terms of two parameters: hydrogen flow and transmission distance” (Yang C and Ogden J, 2006a).

One pathway not trialled by CUTE for externally produced hydrogen, was supply via pipeline. The justification was “Hydrogen from a central production plant could in principle be delivered to the CUTE filling stations by pipeline. In Europe, however only circa 1,000 km of hydrogen pipelines exist and none of them runs near one of the CUTE facilities.” (CUTE, 2006, p30). This is perhaps an oversight as pipelines may have an advantage for certain situations. When considering pipelines we also need to consider the geographic route for pipeline installation (ie: rural or urban), In addition to the two previous parameters of demand and distance.

#### 5.1.1.4 Pathway comparisons

The results from the CUTE project, were categorised in much the same way as Joffe in chapter 4 (Joffe D and Strachan N, 2007) . These have been defined as:-

Site Preparation	<ul style="list-style-type: none"> <li>Includes for all relevant costs for planning, permits, foundations and connections to various services such as water, gas etc.</li> </ul>
Investment equipment	<ul style="list-style-type: none"> <li>Capital cost of hydrogen production equipment, compressors and dispenser.</li> <li>In the case of trucked in hydrogen, this excludes the hydrogen production equipment costs</li> </ul>
Investment storage	<ul style="list-style-type: none"> <li>Cost for on site storage of hydrogen.</li> </ul>
Maintenance	<ul style="list-style-type: none"> <li>Regular maintenance costs, including replacement of disposables such as activated carbon and spare parts etc. of the relevant investment equipment.</li> <li>In the case of trucked in hydrogen, this excludes the hydrogen production equipment costs</li> </ul>
Operations	<ul style="list-style-type: none"> <li>For electrolyser and reformer pathways, cost includes all relevant costs to operate the plant and produce hydrogen including feed stock, wages etc.</li> <li>For trucked in pathways, this includes the delivered cost of the hydrogen, and utilities such as electricity and nitrogen necessary for running the filling station.</li> </ul>

<sup>20</sup> Based on average fuel consumption of 25kg of H<sub>2</sub> / 100km, and buses travelling 100 km per day



Table 5- 3 below, shows the cost variations of the various stages of the three different pathways used in the CUTE project. The column on the left shows the stages as previously defined. The three delivery methods along the top show a minimum and maximum cost per kg of hydrogen. These were taken from the nine sites and listed in the appropriate column. For example, London used the trucked in case. Site preparation is likely to be affected by the geographic location (real estate prices) and could perhaps explain the wide variation, but all the others should be reasonably consistent across all the projects.

	Electrolysis		SMR		Trucked in	
	Min	Max	Min	Max	Min	Max
Site preparation	0.29	1.22	1.65	1.65	0.63	4.17
Investment equipment (including compression)	2.47	3.48	3.30	4.29	0.42	0.92
Investment storage	0.44	0.73	0.50	0.99	0.33	1.25
Maintenance	1.16	2.32	1.65	2.97	min	min
Operations	5.80	6.24	5.45	5.68	3.96	15.01
<b>Totals</b>	<b>10.15</b>	<b>13.98</b>	<b>12.54</b>	<b>15.56</b>	<b>5.34</b>	<b>21.35</b>

**Table 5- 3 Cost ranges for hydrogen pathways**  
 Figures are in € / kg of hydrogen (2006 costs)

Although these categories have not been broken down into detailed individual components, it does allow some examination of the pathway components. Unfortunately for the trucked in case, it is not broken down into any meaningful figures that could separate the centralised production costs from the delivery costs. This is perhaps a weakness in the project as it does not identify the distribution costs which are not insignificant, especially in the case of gaseous hydrogen. Trucked in hydrogen costs varied significantly by a factor of four. London used liquid hydrogen, trucked in from the Netherlands and that there were liquefaction costs, relatively high losses and also the need to build new cryogenic storage facilities at the refuelling depot in Hornchurch. From Table 5- 3, the investment storage costs for the maximum case is significantly higher than the minimum. It will be shown later in this research that liquid hydrogen storage is more expensive than gaseous hydrogen storage, so it is reasonable to assume that the maximum case relates to London and the lower figures are more likely to be related to Luxembourg or Porto. The supply chain length is not detailed either, which also limits the analysis as trucked hydrogen costs logically increase with distance. The various key points of the categories can be summarised as follows:-

- Site preparation is a relatively small component of the overall cost, except in the maximum trucked case. A figure of €4.17 / kg of H<sub>2</sub> seems very high compared with the other site preparation costs. This could possibly be the costs for London, where a dedicated filling station with liquid hydrogen storage was built. It could be misleading to use this figure in any modelling without further investigation.
- Investment equipment costs show SMRs to be the most expensive, although not significantly more expensive than electrolysis. Trucked in is the lowest cost option as would be expected due to the fact this would comprise mainly compression and storage equipment. Since storage costs are broken out, they are easy to evaluate. If we consider the investment equipment costs including compression (1) as being the cost for the remaining main items of equipment (production and compression) it is possible to break down the figures further. Since "trucked in" has no production equipment costs it is reasonable to assume that this is primarily the compression cost. By subtracting the trucked in costs (2) from (1) it is possible to find the production equipment costs (3). Whilst there are some assumptions made, it does enable closer comparison of where site equipment costs are most expensive. For example, we could conclude that for Electrolysis, production equipment = £2.05 to £2.56, storage = £0.44 to £0.73 and compression = £0.42 to £0.92.

	Electrolysis		SMR		Trucked in	
	Min	Max	Min	Max	Min	Max
(1) Investment equipment (including compression figures taken from Table 5- 3)	2.47	3.48	3.30	4.29		
(2) Investment equipment (assumed compression only taken from Table 5- 3)	0.42	0.92	0.42	0.92	0.42	0.92
(3) Investment equipment cost (excluding compression)	2.05	2.56	2.88	3.37		

**Table 5- 4 Investment equipment cost breakdown for production and compression**  
Figures are in € / kg of hydrogen (based on 2006 prices)

This table shows that:

- Storage costs are fairly consistent as would be expected with the max trucked in case, possibly including the additional costs for liquid storage at BP Hornchurch (the London refuelling station).
- Operating costs are generally the highest portion of the overall costs. This would be expected, as it includes costs for feedstock, natural gas, electricity etc. The maximum case for trucked in is significantly higher than other pathways, but the reason does not appear to be explained in

the report. Two pathways were used, trucked in liquid and trucked in gaseous hydrogen. It may be, that they are at either end of the min / max range but it is not obvious which is which. Liquid hydrogen trucks can carry ten times the capacity of gaseous hydrogen trucks, but liquefaction costs are greater than compression costs. Consequently, the figures should be treated as questionable without further investigation. It may be possible to verify these figures later in the modelling section (chapter 8).

### **5.1.2 The operating and maintenance facilities**

One aspect of the CUTE project that was not considered significant by others in the literature review in chapters 4, is the specialist maintenance requirements of Fuel Cell buses compared with conventional diesel powered buses. As part of this review, the author visited the facilities for the London CUTE project at Hackney and interviewed Mr. Alan Coney (Coney A, 2004). For London and Barcelona, the workshops for the three hydrogen powered buses were built specifically for the project. Due to the hazardous nature of hydrogen gas, the workshops had to be deemed a hazardous area and hence all internal equipment certified for use in this environment. This affected all the electrical systems, such a power and lighting. Ventilation fans were required inside the building roof to extract any hydrogen gas release as well as fire and gas detection equipment installed. In addition, the vents on the buses had to be piped outside to a safe area. There were other additional safety issues such as the use of "spark proof" tools and anti-static overalls for maintenance staff etc.

Although it does not appear to be quantified, this probably added a significant cost to the bus operating costs, particularly as nine workshops (one per city) had to be either built or upgraded for only twenty seven buses. Any future fleets are likely to be significantly larger and hence the unit cost for buildings would be reduced. For this reason, it may be considered appropriate to exclude such costs from any modelling, especially if considering larger fleet sizes of more than 50 vehicles, however this remains an area of uncertainty.

### **5.1.3 Environmental impact**

Considering that one of the stated aims of the CUTE project was to *"reduce the global greenhouse effect in line with Kyoto protocol"* (CUTE, 2006, p8), and that *"assessing the environmental impact of the fuel cell bus including the provision of hydrogen is a central element of the CUTE project"* (Binder M and Faltenbacher M, 2006, p 77), surprisingly little was written on the subject in the final reports. Deliverable No.6 does not appear to report on the environmental impacts at all, and the

detailed summary of achievements only allocated four out of the one hundred and ten pages in the report to this issue.

The project used Life Cycle Analysis (LCA) to compare the FCV with more conventional diesel and CNG equivalents. This is particularly relevant here as the FCV is effectively "zero emissions" at the point of use, but the hydrogen production and supply system can be a significant contributor to the overall emissions, whereas 80% of a diesel bus total emissions occurs at the point of operation (CUTE, 2006, p80)

Before reporting on the results published, it is worth noting that an on site reforming process does not lend itself readily to CO<sub>2</sub> reductions and electrolysis emissions are dependent on the source of the electricity. When comparing results it needs to be considered that CUTE focused on feasibility rather than efficiency and many components were chosen on the basis of a proven track record rather than the most up to date technology. Unfortunately, the results reported were comparative rather than absolute figures, tending to measure against a baseline Euro 3 diesel bus in terms of emissions. Rather than measure simple CO<sub>2</sub> emissions a more complex (and less clear) comparison was made.

Four emissions metrics were considered:-

- E 1. Primary energy demand from non renewable sources
- E 2. Global warming potential
- E 3. Summer smog forming potential
- E 4. Acidification potential

Three bus cases were considered:-

- B 1. Hydrogen from small scale on site reforming of the CUTE trial bus
- B 2. As (B1) but based on the CUTE predecessor, the NEBUS which was the first Mercedes fuel cell bus (CUTE, 2006)Hydrogen from electrolysis using hydropower electricity and the CUTE trial bus

The results were fairly predictable in that, hydrogen buses showed advantages over diesel when measured against emissions (E3) and (E4), only bus case B3 showed advantage over diesel when measured against emissions (E1) and (E2). The report findings concluded that *"the environmental profile of the hydrogen FCV bus system is highly dependent on the chosen hydrogen supply route"* (CUTE, 2006, p80).

It would seem from this conclusion that pathways should be modelled from an environmental, as well as an economic point of view. However it is difficult to draw a comparison if all four emissions metrics are used, especially as aspects, like "summer smog forming potential" will depend on city specific factors such as ambient temperatures, local geography, prevailing winds etc. For generic emissions models it may be easier to simply monitor emissions of the most prevalent greenhouse gas (carbon dioxide).

#### **5.1.4 Lessons learnt**

Hydrogen compression proved to be the most unreliable component of the station units with almost 50% of downtime attributed to compression (CUTE, 2006, fig 2.2.4 p34). This is presumably referring to the compressors used for filling the buses. It is perhaps surprising considering that hydrogen compression technology is relatively mature and yet clearly not very reliable. A failure of this proportion would normally be identified as an area for further research, but in this case it may be that faults are related to poor selection and maintenance of equipment, which are areas that would improve as experience develops. This also needs to be put into context as the station units (which included compression) averaged about 85% availability.

The availability of the hydrogen production units appeared to be about the same as the station units (85%). The largest cause of downtime for the electrolyzers is related to safety devices and alarms including leaks, which accounted for more than 70% of downtime (CUTE, 2006, fig 2.2.6 p35). By contrast the reformer did not have any down time attributed to the same factors. The most unreliable element proved to be the reformer itself accounting for about 45% of downtime. Again, given the maturity of the technology, this is unusual and would probably rise to typical industry levels of plant reliability with increasing operating experience.

Hydrogen losses varied according to each site. For sites with relatively few problems, this was between 5 to 10%. Stuttgart had losses of 46% due to contamination as a result of equipment failure. London suffered losses of 69% due to boil off of the hydrogen liquid (CUTE, 2006, fig 2.2.9 p37) This is perhaps not surprising given that one tanker of liquid hydrogen contains about 3600kg. The three buses would only require about 112kg of hydrogen per day. In other words, one tanker of stored hydrogen would last 32 days. Hydrogen is stored in liquid form at approximately -253 °C, at a boil off rate of 1% per day, this would account for about a third (32%) of the 69% losses that London suffered. London appears to have been disadvantaged by using tanks far too large for its usage rate.

Whilst equipment failure can perhaps be discounted in any modelling, it is clear that supply must be matched to demand for trucked in applications (London) and that perhaps a loss factor should be included. This would be analogous to electricity, where the price delivered is after transmission losses. For evaluation purposes, hydrogen costs should perhaps be on the same basis.

Other data from the project showed that costs for site preparation and storage are not significant (Binder M and Faltenbacher M, 2006, p 7), and could perhaps be excluded from any modelling. Maintenance costs varied between 5 to 8%<sup>21</sup> of capital cost (Binder M and Faltenbacher M, 2006, p 7), although this does not appear to be consistent with the figures in Table 5- 3 also supplied from the same source, which reports maintenance costs of between 11% and 19% of capital costs.

### 5.1.5 Future scenarios

Although CUTE was a demonstration project, it appears that a limited amount of modelling was conducted on future scenarios using data acquired from the project and projected future demand. It is based on EU policy objective of 2% of fuel demand in the public transport sector being met with the substitution of hydrogen as a fuel by 2015. Some cost results and conclusions were published which are reported here, Key results and conclusions were:

- To achieve the target of 2% approximately 6059 current diesel buses would need to be converted to hydrogen powered FCVs (Binder M and Faltenbacher M, 2006, p47)
- Non operational costs for future scenarios decrease to approx. €2 to €2.5 per kg of hydrogen produced by electrolysis. Whilst equivalent costs for hydrogen produced by SMR was between €1.5 to 2.25. (Binder M and Faltenbacher M, 2006, p 5).
- Economics of “up-scaling” future plants were calculated using the 6/10<sup>th</sup> rule. (Binder M and Faltenbacher M, 2006, p 5), which assumes that there are economies of scale when considering increased plant size. This method calculates that it is cheaper to produce hydrogen on a per kg basis using larger plants whether this is Steam Methane Reformers (SMRs) or biomass gasification.
- The report also predicts increased efficiencies in future scenarios. Table 5- 5 summarises the cost ranges of the pathways considered, based on fixed energy costs of 10 Eurocents / kWh for electricity, 5 cents / kWh for natural gas, and 5 Eurocents / NM<sup>3</sup> for Nitrogen.

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<sup>21</sup> This figure is quoted without a basis of time. It is therefore assumed to be over the operational life of the project (two years). This equates to an OPEX cost of between 2.5% to 4.0% per annum.



	Current costs €/ kg H <sub>2</sub>	Future costs €/ kg H <sub>2</sub>
On site Electrolysis	12.0 - 16.4 (fig 3)	8.0 – 9.0 (fig 7)
On site SMR	12.0 - 14.8 (fig 4)	4.8 – 5.4 (fig 8)
Trucked in	5.00 - 22.0 (fig 5)	not considered

**Table 5- 5 Comparison of current and future hydrogen costs potential**

Figure references are taken from (Binder M and Faltenbacher M, 2006)

One aspect of the modelling, which is of particular interest, is reported on page 6 of deliverable No.6. It compares the cost of hydrogen produced by an on site SMR with an electrolyser, for varying costs of electricity and natural gas. As one would expect, the benefits of SMR versus electrolysis, depend heavily on the energy costs at either end of the range. Low natural gas price favours SMRs, low electricity cost favours electrolysis. However there is a price band in the changeover region where distribution, equipment, maintenance and site preparation cost can be decisive in determining the best solution. This implies that modelling energy costs alone would too simplistic to determine optimum hydrogen pathways.

Whilst the CUTE project appears to have addressed many issues relevant to costs, safety, technology etc., surprisingly little was reported on environmental impact. It is possible that this was addressed further in one of the reports which were not released for public dissemination. Even though the project considered costs, the number of pathways tested was also quite limited.

CUTE deliverable number 8 (Binder M et al., 2006, page 60) does report on the Global Warming Potential of various pathways compared with the base diesel case, but these are not broken down further into production, manufacturing etc. It concludes that only the hydrogen pathway using electricity generated from a renewable source is better than the base diesel case. This draws an interesting comparison with the GWP of pathways identified by Ally in section 5.1.6.

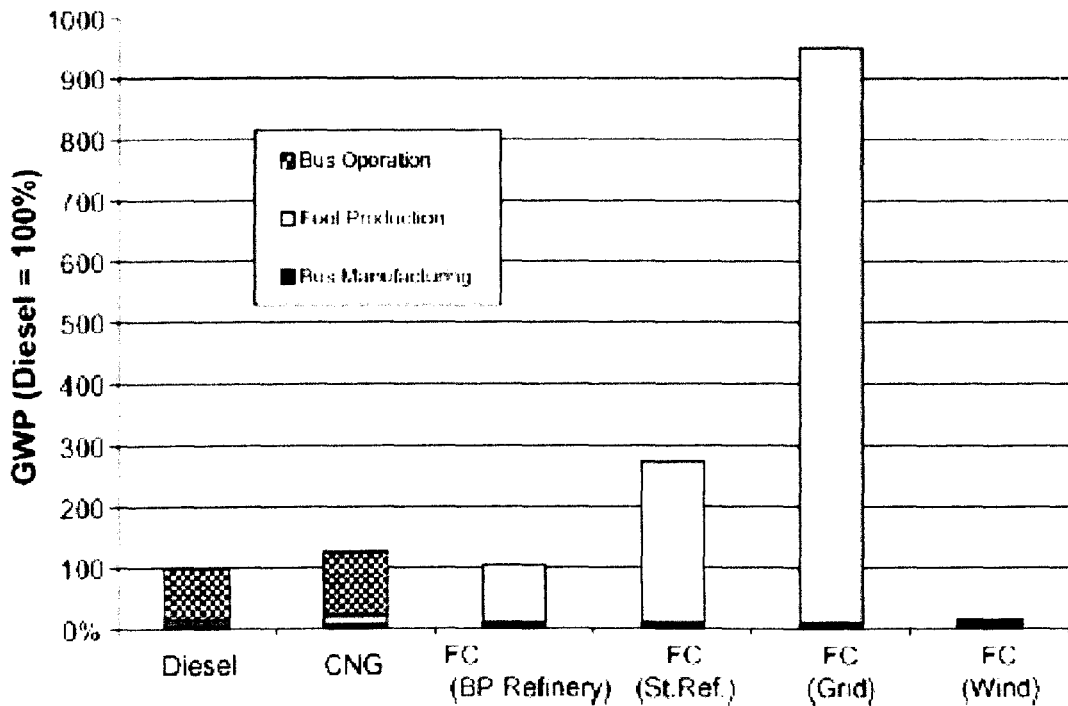
Sustainable Transport Energy for Perth (STEP) and CUTE agree on CNG and hydrogen produced from electricity generated from renewable sources. There are significant differences in the SMR pathways; STEP reports GWP as 1.8 times diesel, yet CUTE suggests a figure of 1.4. The hydrogen from electrolysis using grid electricity pathway has even wider discrepancy. STEP reports GWP as 8.5 times diesel, yet CUTE suggest a figure of 3.7. This could be justified by the different electricity mixes used in the two countries.

### 5.1.6 Other related projects

In addition to the 27 buses trialled in the CUTE project, there are several other associated projects. ECTOS, an Icelandic project trialled three hydrogen powered vehicles in Reykjavik. Also funded by the European Union under their 5<sup>th</sup> framework agreement, it was partly run in parallel with CUTE. The hydrogen supply pathway was on-site electrolysis. Hydrogen is of particular interest to Iceland, due to the country's large reserves of geothermal energy which is a source of renewable electricity. Hydrogen may be the energy carrier which can be used to store this source of energy for export.

Another project similar to CUTE, was the Sustainable Transport Energy for Perth (STEP) project which started in 2004 and was funded and organised by the Department of Planning and Infrastructure of Western Australia. It also involved three fuel cell buses, run over a two year period using hydrogen produced using a slightly unusual catalytic reforming process where it is claimed that the hydrogen is produced as a refinery by-product. It was produced at the BP Kwinana refinery, transported by a 2 km pipeline where it was purified using a Pressure Swing Adsorption (PSA) process before being compressed and transported a further 66km in gaseous form by road to the bus depot (Ally J and Pryor T, 2007). This hydrogen supply pathway is similar to the CUTE gaseous pathways except that purification appears to be carried out at an intermediate point.

In a review of the STEP project Ally also concluded that the current hydrogen infrastructure suffered from *"not being properly sized. Purification equipment, compressors and even transport trailers operated on an intermittent as needed basis"*. Hydrogen losses were still significant at 2.4%, although considerably better than achieved on the CUTE project. Ally also studied the Global Warming Potential (GWP) of several pathways using diesel as a base line and concludes that the process used at the BP Kwinana refinery has a significantly lower GWP than hydrogen produced using the Steam Methane Reforming (SMR process). However, according to Ally, it is still no better than the base case diesel, as shown in Figure 5-6 below.



**Figure 5-6 - Global warming potential (GWP) of various pathways**  
(Ally J and Pryor T, 2007, fig 5 P408)

Ally defines Global warming Potential (GWP) as “emissions that contribute to global warming” and gives examples as “CO<sub>2</sub>, CH<sub>4</sub> etc.”, whilst not exactly the same measures used in the modelling in chapter 8, results should be expected to be similar. It would appear that diesel is the “cleanest” of fuels here with the exception of hydrogen production by wind generated electrolysis.

It is not possible to comment further on the FC (BP Refinery case) without detailed knowledge of the production process but these results could be accurate if a use for some of the by-products could be found within the refinery and hence removing it from the emissions chain.

The FC wind option appears to show zero emissions for the production of hydrogen. This is only correct if the energy used for compression or liquefaction is also based on wind powered electricity generation.

## 5.2 Promoting Unst Renewable Energy (PURE)

On the Shetland island of Unst the PURE project was commissioned in 2005. It consists of 2 wind turbines, each capable of generating 15kW of electricity connected via a load management system to an electrolyser with a capacity of 3.55 Nm<sup>3</sup>/hr (approx 7.75kg / day) of hydrogen for use in a 5kW fuel cell. It is a small scale project, and the hydrogen production capacity would not even provide enough energy for one London bus.

The total project funding was only £350,000 including all management and engineering / hardware costs and involved a number of institutions. The European Regional Development Fund (ERDF) provided much of the funding, with some funding from the Shetlands Island Council. A hydrogen fuel cell technology specialist company, siGEN provided much of the management and engineering technology, with academic input from Robert Gordon University.

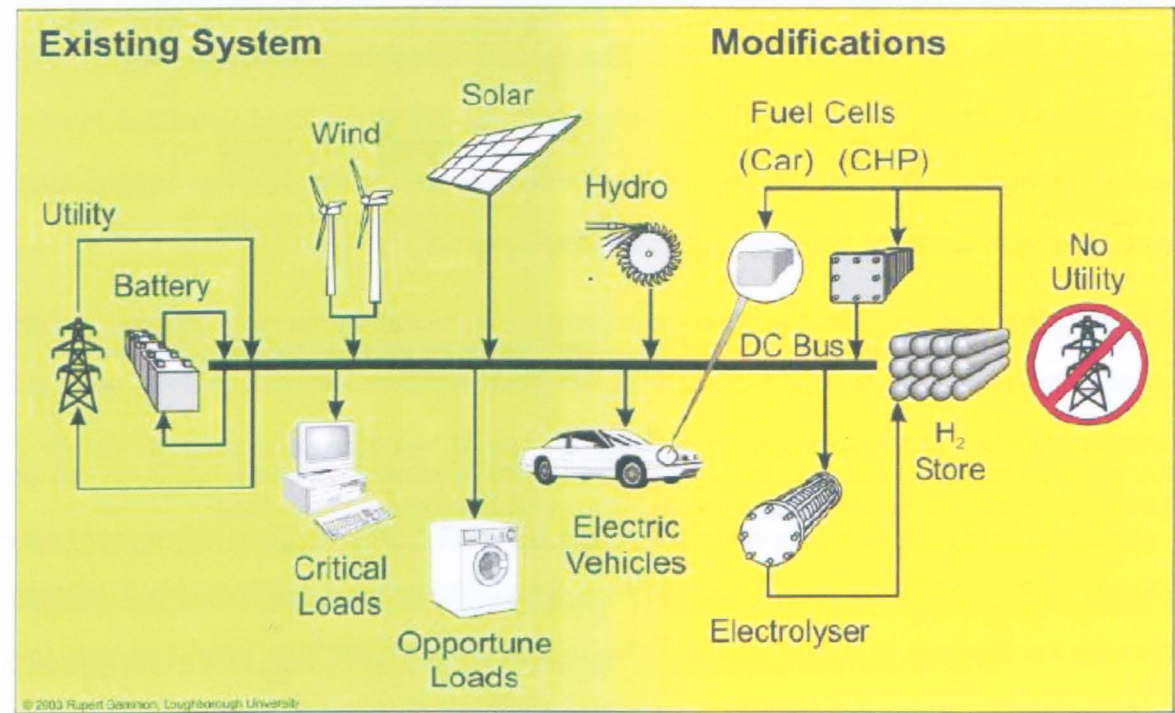
The project's primary function is to provide electricity from a renewable source to the local industrial estate, it is also planned to provide some heat to the industrial units (residual from the fuel cell). In addition, the Unst partnership aims to promote the use of hydrogen as a potential fuel for the island's vehicles. This would reduce their reliance on imported hydrocarbon fuels.

Although the transport element of the project is limited, it applied a relatively novel approach, involving the purchase of a small 4 seat battery powered electric car from India. This cost about £6,000 and has a range of about 50km. It was then converted to hydrogen by fitting a fuel cell. The hydrogen onboard storage was achieved using small metal hydride cylinders about the size of a fire extinguisher. The vehicle is capable of holding up to three cylinders, giving a total range of more than 100km. The system is consistent with the view held by Professor Guo in chapter 4 that solid storage systems could be rechargeable. Information was provided in a telephone interview with Sandy McCauly (McCauly S, 2004).

However, whilst this project does use hydrogen for transportation purposes, it does not have a supply and distribution system worthy of further study as the transport element of the project is limited to a single fuel cell powered vehicle. Unst has a total population of less than 1,000 people and only 120km<sup>2</sup> of land, it is unlikely to be large enough to develop a significant hydrogen powered transportation system.

### 5.3 Hydrogen and Renewables Integration project (HaRI)

The Hydrogen and Renewables Integration (HaRI) project is based at West Beacon Farm in Leicestershire. Figure 5-7 below shows a number of aspects to the project but in general it is related to the efficient use production / storage and use of renewable energy. The interesting part of the diagram concerns the two “energy storage” systems at either end of the DC Bus. At one end, is conventional electricity storage which was achieved with the use of second hand submarine lead acid batteries and at the other end a hydrogen storage system.



**Figure 5-7 HaRI project schematic diagram of energy network (Arnaud E, 2006)**

The hydrogen system consists of a 36kW electrolyser with a demineralised water plant, a compressor capable of compressing about 8Nm<sup>3</sup>/hr, two high pressure fixed storage systems at 137 barg, giving a total storage capacity of about 3000 Nm<sup>3</sup>. This equates to about 270 kW hours of storage. The fuel cell converts the hydrogen back to electricity at the rate of 2kW and also provides 2 kW of residual heat. Oxygen, the only other by-product from the fuel cell is currently vented. During the visit, it was revealed that, to date, their systems showed that they had produced twice the amount of hydrogen in the electrolyser than they had in storage the storage tanks, implying 50% losses in the pipe work and storage systems. This is because hydrogen is a difficult gas to store for reasons explained in section 1.2.

The hydrogen aspect of this project was an addition to the existing site, installed and run by Dr. Rupert Gammon. Its primary purpose is to provide an alternative method of storing energy produced by the various electricity generation systems on the farm. It is hoped that hydrogen may be the best solution for large scale storage of energy and to enable the farm to operate completely independently of the electrical grid. This is consistent with earlier claims that hydrogen has a significant advantage over conventional batteries in terms of energy storage densities.

However the HaRI experience is of limited relevance to this research project. Static storage systems such as this are not generally constrained by size and weight limitations applicable to on board storage and vehicle range would also not be an issue.

As this project is privately funded, very little data was available on costs. However it does have most of the stakeholders required to achieve a successful project. Funding was provided by a local entrepreneur (Tony Marmont). Management and engineering technology, as well as academic input was provided by CREST (Centre for Renewable Energy Systems Technology) based at Loughborough University). Although this project has hydrogen production and storage elements, it does not have a distribution system worthy of further study for the purposes of this project. (Gammon R, 2004)

## **5.4 Camelford and District Bus project**

The Camelford bus project was intended to provide a community bus service between Delabole and Camelford in Cornwall. The project's aims were similar to the UNST project, to link renewable energy to a local community project and provide transport in a rural area.

The intention was to use electricity, either from a new wind farm or the grid (depending on wind conditions) to produce hydrogen in an electrolyser which would then be compressed and stored. Any additional electricity generated by the wind farm was to be fed into the grid. The hydrogen would be used to power local community mini buses, driven by electric motors powered by fuel cells with on board gaseous Hydrogen storage.

The project stalled due to a funding issue (Shaw A, 2004) when Ford, the supplier of the buses, withdrew from the project. It is an example of the need to have relevant stakeholders in place to ensure a project's success. A revised plan involved the use diesel powered buses as an interim solution, thereby negating the "green aspect" of the project and any relevance to this PhD research.



Considering the support infrastructure required for the CUTE project to keep the buses on the road, it is difficult to see how the Camelford bus project could have progressed without a major source of funding being found as well as technology support for both the hydrogen system and bus maintenance.

## 5.5 Teesside hydrogen project

Teesside is one of the main hydrogen production centres in the UK. It is also the home of the Tees Valley Hydrogen project with the stated aim, “to develop industries related to the hydrogen economy and low carbon technologies from an existing assets and skill base (particularly relating to hydrogen)”. Rather than being a explicit project, this is more a case of an area with specific skills and expertise trying to expand into new markets in a manner similar to using the technology push method of marketing.

In March 2008 Wind Hydrogen Ltd announce plans to produce hydrogen for use locally from electricity generated by wind turbines (Wind Hydrogen, 2010). However, at present none of these projects appear to have a significant transport element planned. There were no demonstrator vehicles running on hydrogen in the Teesside area at the time of writing, but the plan is to sign up local vehicle fleets to a reduce the carbon content in fuels over a ten-year period. The project will be supported by the installation of a green fuel station dispensing compressed natural gas and hydrogen, plus mixtures of the two. This will be one of the first Hythane<sup>22</sup> stations when / if it opens. This is another potential route to the transfer to hydrogen as a fuel. The project is scheduled to be implemented over the five years from 2004<sup>23</sup>.

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<sup>22</sup> Hythane is a commercial name for a mixture of hydrogen and methane.

<sup>23</sup> At the time of writing (Feb 2010), plans do not appear to have progressed in this area as there are no hydrogen re-fuelling stations in the Teesside area. Ref: <http://www.nctinform.net/h2/H2Stations/Default.aspx>

## 5.6 Project Funding

By far the largest fund supplier for hydrogen demonstration projects for transport within Europe is the European Union. The EU has funded hydrogen related projects under their 6<sup>th</sup> framework program (FP6). The funding was broken down into different areas of research as shown in Table 5-6.

Research area	No. Projects	value (€million)
Hydrogen Production and distribution	15	56.29
Hydrogen storage	7	26.18
Fuel cell research	14	49.23
Stationary and portable applications	7	19.00
Transport (including hybrid vehicles)	13	57.45
Pathways and socio-economic analysis	14	23.20
Technology validation and demonstrations	4	46.67
Safety, regulations and codes	10	16.16
Totals	84	€ 294.18 million

Table 5- 6 EU funding of hydrogen related projects  
(EU, 2006)

CUTE received €19 million of EU funding as part of the technology validation and demonstration funding budget. Another UK project funded by the EU relative to this research (under the section on hydrogen production / distribution and storage) was CACHET (EU, 2006), which is a research project by BP to reduce the cost of CO<sub>2</sub> capture and sequestration during natural gas reforming of hydrogen. This had the aim to cut costs to about €20 - €30 per tonne (EU, 2006, p 18). The total value of the funding for this project was €7.5 million.

Of the €294 million allocated to funding of hydrogen related projects, less than 10% was allocated to projects related to distribution pathways and this had to be shared with research into socio-economic issues related with hydrogen. HYWAYS was a typical project which was provided with €4 million to develop a roadmap for the introduction of hydrogen into the EU energy system. This appears to be typical of the EU funding in this area. The project was not completed until 2007 (after the period of this case study review) and hence not reviewed in detail here, but it reached some interesting conclusions. For example, that hydrogen could be competitive as long as oil remains above \$60 per barrel. It also concludes unless vehicle on board storage is in liquid form, the only part that liquid hydrogen will play is to deliver excess capacity from existing liquefier plants.

It also goes on to say that “in later phases with increasing hydrogen demand, a high share of hydrogen is produced centrally and the pipeline contribution will increase significantly” (EU, 2008b). Further reading on this project is available at the HyWays website – <http://www.hyways.de>.

The focus generally seems to be more related to how it might happen if it was viable, rather than how it can be made viable. Whether there is insufficient research interest into hydrogen pathways or whether this is due to the fact that hydrogen distribution and supply projects are required to be part of a wider project which encompasses the complete system (such as CUTE) is not clear.

Within the UK, the Engineering and Physical Sciences Research Council (EPSRC) are one of the main funding bodies for funding research into energy. In 2007/2008 £70 million was made available for research, of which £15 million was earmarked for research into fuel cell and / or hydrogen technologies<sup>24</sup>. Whilst funding into hydrogen research and development has increased significantly from the €294 million allocated in Table 5- 6 to €470 million announced as part of the 7<sup>th</sup> European Union framework programme (EU, 2008a) during the period this PhD research has been under way, it is still not sufficient to fund many large scale demonstration projects. Perhaps the largest scale research within the UK at present is the Sustainable Power Generation and supply project (SUPERGEN), part of which is researching how hydrogen can be produced, stored and distributed sustainably. This is being led by the Universities of Oxford and Bath, the funding is worth £3.5 million over a four year period.

## **5.7 Summary of demonstration projects**

Although this has been a brief review of research and demonstration projects, the main project of relevance in the UK is the London element of the CUTE project, although useful data are available from the remainder of the CUTE European projects as well as the ECTOS and STEP. Other worldwide hydrogen projects have been listed in Table 6-1. . CUTE involved the transportation and distribution of a significant amount of hydrogen, even though it was limited in the variety of supply and distribution pathways. There is a reasonable amount of cost data published in the reports including some projections for future scenarios. Some of the CUTE data, such as bus fuel consumption may be useful for the modelling described in chapter 8. Hydrogen pipeline pathways were not evaluated and it may have been helpful if at least one of the CUTE depots were stationed

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<sup>24</sup> Data obtained from department of Business Enterprise and Regulatory Reform <http://www.hfecat-demo.org/>.

nearby to a pipeline. However it is recognised that a pipeline to supply just three buses would be unlikely to be economically viable even if only a few hundred metres long.

Other projects such as PURE and HaRi could be modelled as on site hydrogen production cases, but the data for comparison does not appear to be in the public domain. Also, the actual volumes of hydrogen produced are relatively small and hence results may be skewed. Other UK based projects and initiatives do not have any content relative to this thesis.

The Hyfleet CUTE project, which expands the original CUTE demonstration project up to 47 buses world wide, started in 2006 and the buses travelled more than 2.5 million kilometres. What is most interesting is that they seem to be considering the use of hydrogen in Internal Combustion engines as well as producing hydrogen from Liquefied Petroleum Gas (LPG) and Biomass. This is a promising development on the original CUTE project which seemed heavily focused on the buses themselves rather the pathways in which hydrogen is supplied. The project finished in, 2009 and results disseminated at the Hyfleet final conference held in Hamburg on November 17<sup>th</sup> and 18<sup>th</sup> 2009. Timescale does not permit detailed analysis of the conference and its conclusions but the titles of two of presentations perhaps point where the current view is with respect to hydrogen as a road transport fuel.

- Climate change, Transport and Hydrogen – is Hydrogen part of the solution or just another problem? - Prof. Dr. Olav Hohmeyer (Hyfleet - CUTE, 2009)
- Batteries and Fuel Cells – Jan Mücke (Hyfleet - CUTE, 2009)

Two of Professor Hohmeyer's conclusions in his presentation are that hydrogen will be a choice as a fuel if:- *“cheap surplus electricity from renewables becomes massively available”* and / or if *“it offers a better/ cheaper storage solution for energy in a car or truck as batteries storage”*. Jan Mücke appears to concur in his presentation for the future when he states *“in the long term, the focus will be on the development and introduction of battery and fuel technology, because the future belongs to efficient electric mobility using batteries and fuel cells”*.

## **5.8 U.S DoE models**

So far in this chapter, the focus has been on case studies of demonstration projects or at least feasibility studies of such projects. It has been somewhat limited in terms of hydrogen supply and distribution pathways and the only significant pathways are specifically focusing on buses, as the ECTOS, STEP, CUTE and Hyfleet projects have shown. This next section focuses on specific work by the US Department of Energy and although it cannot be considered a demonstration project, it

has particular relevance to this research and hence worthy of review. This is particularly relevant due to the modelling work being carried out later in this research thesis.

In 2008 the US Department of energy published a series of Excel based spreadsheets on their hydrogen program web site (Milliken J, 2008), as part of the United States hydrogen program. The US DoE models are comprehensive as one would expect from the significant list of contributors from both the academic world and industry.

The website produced the following set of models, which are relevant to this PhD research:-

1. Central hydrogen production analysis
2. Distributed hydrogen production analysis
3. Production case study work sheets
4. Hydrogen delivery analysis – components model
5. Hydrogen delivery analysis – scenarios model

The analysis models (1, 2, 4, & 5) above, will be reviewed in this section for both approach and content. The case studies results (3) will be used later in chapter 7 for testing of the model used in this research. The key elements of the US DoE models can be summarised as:-

- Distribution network model at the city wide level for private vehicles.
- Two models are used, one for production and one for delivery.
- Each pathway requires a separate case study, allowing different inputs for each pathway.
- Emissions are broken down into “upstream” and “on site” rather than each stage of the pathway.
- Electricity energy costs do not appear to allow a mix of sources and hence emissions, presumably fixed on average US mix.

### **5.8.1 Production Analysis models**

The two production analysis models consider hydrogen production via the following methods:-

- Centralised biomass gasification
- Centralised grid based electrolysis
- Centralised coal gasification (with and without carbon sequestration)
- Centralised natural gas reforming (with and without carbon sequestration)
- Centralised nuclear high temperature electrolysis
- Distributed electrolysis
- Distributed natural gas reforming
- Distributed ethanol reforming

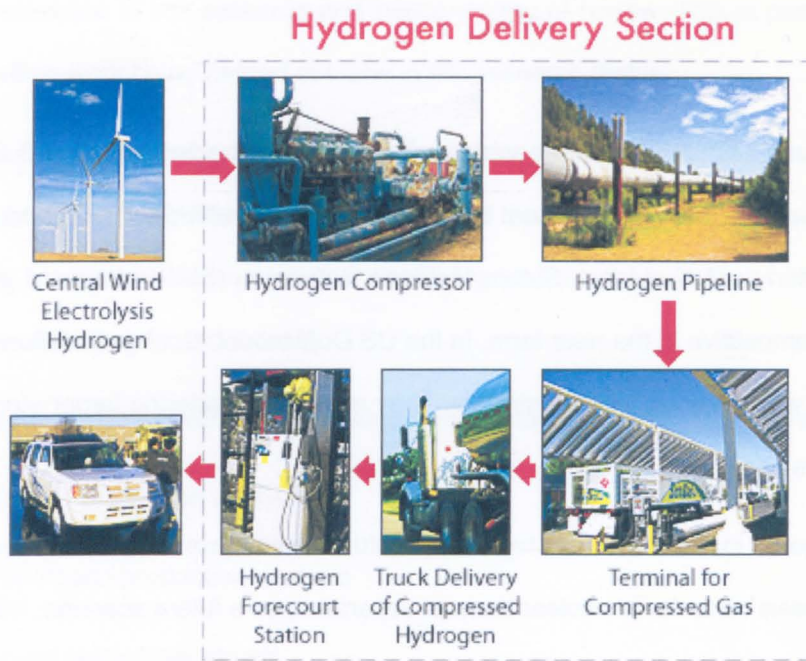
The reforming process has numerous variations, allowing hydrogen to be produced from almost any hydrocarbon feedstock (gas, oil, coal etc.). Earlier reviews of the various production processes showed that within the UK at least, Steam Methane Reforming (SMR) of natural gas is likely to be the most cost competitive in the near term. In the US DoE model, Coal gasification is considered. It is possible that within the US energy strategy, they may be considering larger stocks and cheaper sources of future coal.

The US DoE model includes nuclear high temperature electrolysis, whereas an earlier production review in this thesis considered nuclear thermal separation as a future scenario. Interestingly, there is no “current” case study on the US DoE web site (US DOE, 2009). There is only a future case, with a start year date of 2030. It is therefore reasonable at the present time to exclude this option. The localised (or distributed) production methods were similar to the CUTE project, although the US DoE considered Ethanol reforming in addition. Details of the authors and organisations and key data can be found in Appendix 2 & Appendix 3.

### **5.8.2 Delivery Analysis model**

The US DoE delivery model is in two parts, a components module (which calculates costs of compressors, pipelines, tankers etc.) and a scenario module which appears to calculate overall delivery costs averaged over a plant life time. The US DoE delivery analysis is based on a distributed network and hence includes for both pipeline and tanker distribution systems in the same scenarios, including demand.. The component elements from the US DoE web site (Milliken J, 2008), will now be reviewed separately.





**Figure 5-8 US DoE delivery model boundaries**  
(Milliken J, 2008)

### 5.8.2.1 Compressor costs

The US DoE model uses a wide range of compressor costs, starting at 306kW ranging up to 18MW and appears to use costs for equivalent natural gas compressors.. Although different, it is common to base hydrogen equipment costs using natural gas equipment costs (eg: pipelines). It is more important to ensure that compression energy calculations are based on the actual gas due to different physical properties of hydrogen and natural gas.

### 5.8.2.2 Liquefaction costs

The US DoE model projects liquefier costs diagrammatically as shown in Figure 5-9 and the costs vary by plant capacity which is more relevant to a large scale distribution network. Based on the typical values in the US DoE model, a typical cost for liquefaction would be in the region of £1.00 per kg of hydrogen.

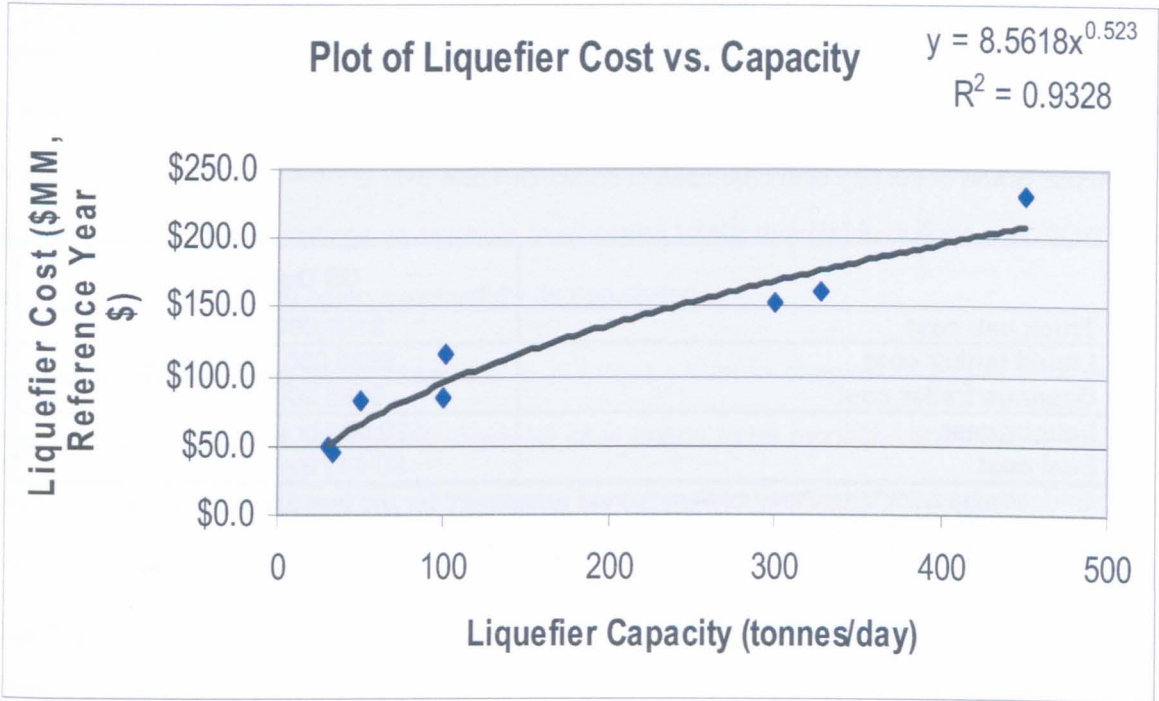


Figure 5-9 US DoE liquefier costs  
(Milliken J, 2008)

5.8.2.3 Pipeline costs

The US DoE produces a number of curve plots for pipeline costs, taking into account costs for material, labour and rights of way (see Figure 5-8) . Pipeline sizes vary from 4" to more than 40" and hence capable of carrying significant amounts of hydrogen, which would be necessary for any distribution network. Costs appear to be base on natural gas pipelines, using the similar justification as compressors test.

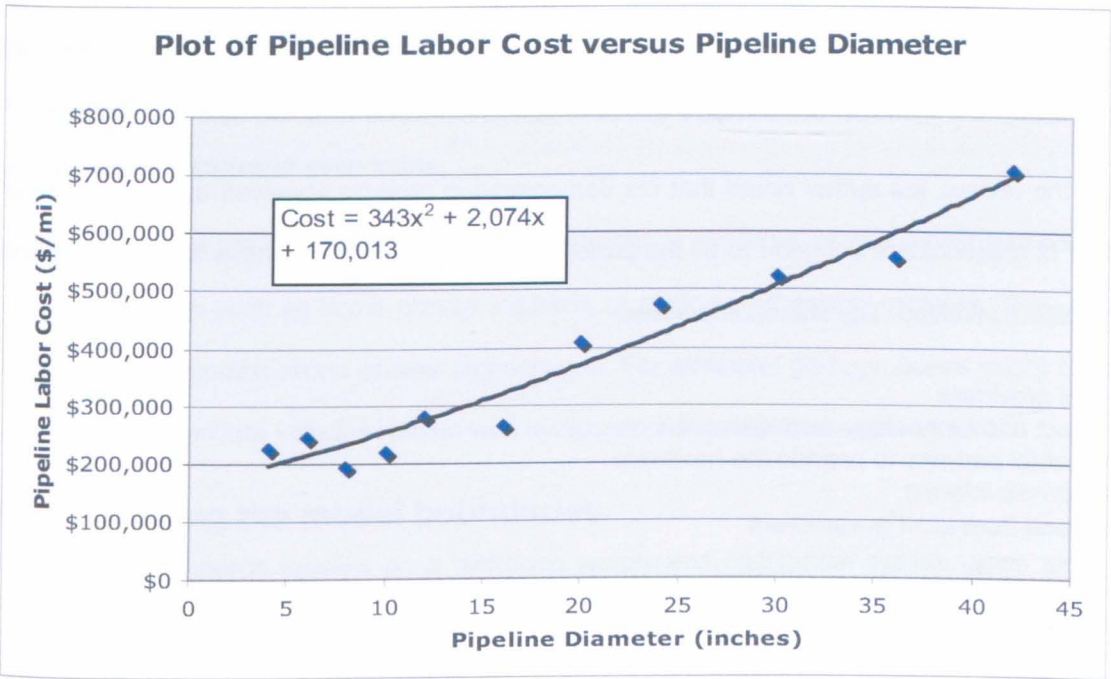


Figure 5-10 Typical US DoE pipeline costs (labour)

5.8.2.4 Road transport costs

The US DoE model calculates hydrogen delivery based on a liquid hydrogen tanker capacity of 3600kg and a two gaseous hydrogen tankers with capacities of 280kg at 2,700 psi and 656 kg at 7,000 psi. Some of the key cost data used is shown in Table 5-7.

	US DoE model
Truck cab cost	\$100,000 (£52,600)
Liquid tanker cost	\$625,000 (£328,950)
Gaseous trailer cost	\$165,000 (£86,850)
Labour cost	\$20.00 / hr (£10.52 per hr)
Fuel cost	\$0.44 / litre (23p / litre)

Table 5-7 Capital cost comparison of equipment for the two different models

5.9 Summary of Case Studies

It is perhaps not surprising, that the number of active demonstration projects is limited. Significant funding is required for large scale demonstration projects such as CUTE and HyFleet, which is most likely to be required from national rather than local government. One example of this is the CDCT project which was largely funded locally but stalled due to a funding issue. There is also a lot of competition for this funding with respect to alternative types of vehicles such as BEVs. What is perhaps surprising is that there was not more small scale projects such as PURE and HaRi. Perhaps it may be that the future of hydrogen is more of a long term solution than near to mid term. Some of the statements at the HyFleet closing conference appeared to support this view with the belief that batteries and fuel cells are the long term future.

In the meantime modelling work by organisations such as the US DoE can perhaps help unnecessary waste of funding on demonstration projects that are least likely to be viable economically. It is the latter conclusion that this research will focus on in the next few chapters.

During the review, the author noted that the demonstration projects reviewed appeared to have a number of stakeholders common to all the projects. Successful projects have had all the relevant stakeholders involved. The stakeholders are:-

- Fund providers
- Project and technology management
- Industrial partners to provide the hardware
- Academic interest
- Support from local government

Projects that did not get off the “drawing board” appeared to have one or more of these stakeholders missing. One example of this is the Camelford and District Community Transport (CDCT) project reviewed.

## **CHAPTER 6 MODELLING METHODS**

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Due to the limited number of demonstration projects in the UK identified in chapter 5, and the relatively high costs of installing different supply chains such as pipelines, it is important to model as many of the different options as possible to eliminate totally unsuitable options and focus in on the most viable, subject to being successfully demonstrated.

Approaches to modelling were addressed to a limited extent in chapters 3 and 4, but before a model can be developed, we need to consider what needs to be modelled and how. It has been shown that the cost of transporting hydrogen can be a significant portion of the end consumer price and at the time of writing, only a few options have been trialled for fleet vehicles, as demonstrated in the CUTE projects. Although there is much hype about hydrogen vehicles and re-fuelling stations, even American states such as California, usually at the forefront of new green technologies do not yet have significant numbers of hydrogen powered vehicles in operation. At the time of writing this consisted of approximately 209 vehicles and 24 re-fuelling stations (Cleantech, 2009).

### **6.1 Modelling choices**

There are a number of possible approaches to the type of modelling suitable for a hydrogen powered transport supply system. Model types can vary from complex models such as the Markal linear programming model typically used for energy system analysis, to simplified spreadsheet calculations. Modelling of systems can vary from single point distribution systems, to complex hydrogen distribution networks. They can consider timescales for transition, or network sizes based on assumed uptakes of hydrogen vehicles. They can also vary by type of vehicle, eg: buses, lorries, private vehicles or even trains.

All models tend to pre-suppose that sufficient hydrogen is available, or that it may also be used for other applications such as home energy supplies, or static power supply systems. They generally do not consider combinations of new technologies. For example, perhaps buses might convert to hydrogen whilst private vehicles remain with hydrocarbons for the foreseeable future.

#### **6.1.1 Defining the model boundaries**

Although this research focuses on a hydrogen supply and distribution system, each step of the supply chain from production to end use needs to be considered. For example, it may be relatively easy to show that liquid hydrogen has a significant advantage over gaseous hydrogen by road

transport, but energy is required to liquefy hydrogen during the production stage. Equally, the cost of storing liquid and gaseous hydrogen can be significantly different.

Within the boundaries of this research “end use” is defined as being up to the point of loading on to the bus, this is sometimes referred to as “well to tank analysis”, although in the case of hydrogen, “well” is not always an appropriate term. However, to make a reasonable comparison with the diesel bus case, it cannot just take into account the amount of fuel loaded onto the bus. Fuel Cell Vehicles (FCVs) have better efficiencies than ICEs, so fuel economy needs to be taken into account. It is therefore appropriate to measure cost and emissions based on distance travelled, typically, this would be £/ km or g of CO<sub>2</sub> / km.

A true cost and emissions comparison would need to take into the actual cost of the buses, including maintenance etc. This presents a problem, as the only costs available are those related to CUTE, which were bespoke designs, for both the buses and maintenance systems. For this reason, it has been decided to exclude these costs from modelling. This approach is justified via two arguments. Firstly, this research is concerned with infrastructure rather than vehicle technology and secondly, because to date there is no reasonable cost estimates for the buses outside the CUTE project.

It is also a common research practice to consider whole life cycle analysis. This can be interpreted to include all costs and emissions associated with the project. Specifically, purchase of land, reinstatement of land at the end of a given period and even emissions due to the manufacture of component parts of the equipment such as compressors. Although these issues are important, they need to be considered in the context of the accuracy of any model. For example:-

- Pipeline costs estimations can vary by +/-25% (refer to chapter 7).
- Production cost estimates can vary by 100% (refer to chapter 3).
- During the period of this research oil prices have almost doubled, reduced by 50% and at the time of writing increasing again. This has significant feedstock effects on natural gas and electricity prices which are inputs to the model.
- Land costs in the UK have risen significantly above inflation but have recently declined in part to their overestimation in the market, ie: they were hyper-inflated.

These variations mentioned above are likely to have a much greater impact on model results than the effect of whole life cycle analysis on modelling. The first two points will be evaluated as part of

the sensitivity analysis testing in chapter 7, the effect of oil prices (and hence diesel prices) will be investigated as part of the analysis in chapter 8. Costs variations, such as the accuracy of pipeline estimations of generic routes and production techniques will affect results far more significantly than the cost of disposal of items such as compressors etc. Therefore it is possible to argue that Life Cycle Costing would not have a significant impact on the modelling results in this research. Thus in summary, the model uses boundaries as follows:

**Model choice 1 - This model will therefore focus on the complete supply chain but will not address issues and costs associated with life whole life cycle analysis, nor will it include the capital and operating costs of the buses. The model will include all production, distribution storage and loading costs.**

### 6.1.2 Defining the type of model

There have been a number of approaches to modelling of hydrogen supply and distribution systems which can be categorised as follows:-

- Single point distribution models that consider a single fleet with a number of different pathways. eg: (Shayegan S et al., 2006) & (Yang C and Ogden J, 2006a)
- Distribution networks that consider an area to be covered, such as a city wide network. eg: (Yang C and Ogden J, 2006a) & (Joffe D et al., 2004)
- Models that consider the uptake of hydrogen based vehicles, based on vehicle numbers without consideration for timescale. eg: (Thomas C et al., 1998) and (Jokisch S and Mennel T, 2009)
- Future scenarios of uptakes on hydrogen powered vehicles and the networks required to supply the hydrogen powered vehicles. eg: (Van Benthem A A et al., 2006) & (Tseng P et al., 2005)

These four basic types of model identified represent the most common approaches to modelling this subject, each has a different approach to the general question of “how hydrogen powered vehicles can substitute hydrocarbon powered vehicles”. The “network” models can perhaps be divided into two categories:-

- Timescale – forecasting potential growth of hydrogen powered vehicles over a fixed time period.
- Vehicle uptake – forecasting networks required to supply an increase in hydrogen powered vehicles, without consideration for timescale.

These types of models tend to pre-suppose that a widespread hydrogen economy is inevitable and that the issue is how to make the transition, using a fairly narrow technologically based perspective. Whilst these models have a clear role to play in a transition to a hydrogen economy one could argue that they are trying to solve 2<sup>nd</sup> stage issues and problems, rather than the 1<sup>st</sup> stage (initial vehicle uptake and optimum pathways). The “single point models” tend to focus in more detail on



the component stages (or steps) of hydrogen supply systems, and more related to 1<sup>st</sup> stage issues. Both types of model will have a role to play in future modelling of future hydrogen energy systems. Whilst it is recognised that single point models will not address the network issues associated with large scale hydrogen vehicle uptake, it is believed that they have a role to play in refining data inputs to 2<sup>nd</sup> stage models and can be used to accurately predict optimum pathways for fleet vehicles. Thus, in summary, this work takes the model approach statement:-

**Model choice 2 - For fleet vehicles, it seems more appropriate to focus on a single point delivery supply chain model as currently there are no city / county wide fleets of hydrogen powered vehicles in service.**

**6.1.3 Buses versus private vehicles**

Several researchers have identified that although buses are a logical starting point, most research to date has focused on private vehicles. Agnolucci, in his paper titled “Hydrogen infrastructure for the transport sector” comments on this, when he writes, *“in the academic and grey literature, great emphasis has been paid to the hydrogen infrastructure for private vehicles rather than freight vehicles .... While it can be argued that freight vehicles – both road and marine – have a number of advantages for the deployment of hydrogen, ie: the size of vehicles, the availability of well trained operators and the need for a limited infrastructure”* (Agnolucci P, 2007). Farrell in his paper entitled “A strategy for introducing hydrogen into transportation” concurs, noting that *“most research into hydrogen as a transport fuel has focused on LDVs”* (Light Domestic Vehicles) (Farrell A et al., 2003).

At present, there are no technical obstacles to powering buses by hydrogen, as CUTE demonstrated. On board storage is not a major issue, the space limitations which affect private vehicles are of little concern for buses, and only a limited fuelling infrastructure is needed. Thus in summary:-

**Model choice 3 - It therefore seems appropriate to focus modelling efforts on fleet vehicles and in particular buses as the primary stage of a transition to hydrogen.**

**6.1.4 Other model related issues and assumptions**

There are a number of other issues related to modelling of a hydrogen powered vehicle transport supply system. These can be summarised as:-

- Hydrogen supply – although chapter 3 identified that there is no significant spare capacity in current hydrogen production in the UK, hydrogen is an abundant element, with relatively mature

technologies to produce it in large quantities. It is therefore reasonable to assume that sufficient hydrogen can be made available.

- **Material issues** – Although not directly related to this research, the potential shortage of platinum for use in fuel cells has been identified as a potential obstacle by some researchers (Dutton G et al., 2005, p6). However, hydrogen can also be burnt in an Internal Combustion Engine if necessary, so it may be reasonable to exclude material technology issues from the model.
- **Technology combinations** – There are a number of competing technologies to the so-called hydrogen economy. Some are hydrocarbon based such as CNG and LNG vehicles, others include technologies such as hybrids and battery powered electric vehicles. If a network distribution model was being considered it would perhaps not be appropriate to focus in on one fuel technology for vehicle types. By focusing on one type of network and vehicle it can be considered appropriate to focus in on one technology. It is more likely that one type of fuel technology will be used for a specific type of transport. Results will need to be compared to a baseline case, which in this case is chosen to be diesel powered buses due to their high penetration in the market.

**Model choice 4 – This model pre-supposes there is sufficient feedstock for hydrogen production, sufficient materials that are required for any new technologies are available, and that hydrogen may not be the only new method of providing alternative energy for vehicles,**

## **6.2 Hydrogen Pathways**

Due to the number of potential pathways identified earlier in this research (refer to Figure 1-2), it is useful to carry out some preliminary evaluation of the most likely pathways. A number of potential pathways will be identified, reduced down to a practical number of options, which can be then modelled and compared with pathways already used in demonstration projects.

### **6.2.1 Pathways used in other projects**

Apart from the CUTE projects, there are a number of other demonstration projects that have been carried out worldwide. Table 6-1 lists a number of these projects identified during a web search of hydrogen transport projects. The initial focus was specific projects, related to fleet vehicles and in particular buses, but it includes other transport related projects (where appropriate). The list is not exhaustive but is a reasonable representation.

Current Pathways in operation				
Projects	Production method	Transport medium	Transport method	On site storage medium
<b>CENTRALISED PRODUCTION</b>				
Connecticut transit [6]	Unknown	Liquid	Road	Liquid
CUTE Luxembourg [1]	SMR	Gas	Road	Gas
CUTE London [1]	SMR	Liquid	Road	Liquid
CUTE Porto [1]	SMR	Gas	Road	Gas
STEP Perth [1]	SMR	Gas	Road	Gas
Munich airport [5]	Unknown	Liquid	Road	Liquid
Kansai, Japan [3]	Unknown	Liquid	Road	Gas
Chicago, USA [3]	SMR	Liquid	Road	Liquid
<b>LOCALISED PRODUCTION</b>				
CUTE Stuttgart [1]	SMR	n/a	n/a	Gas
CUTE Madrid [1]	SMR	n/a	n/a	Gas
CUTE Stockholm [1]	Electrolysis	n/a	n/a	Gas
CUTE Amsterdam [1]	Electrolysis	n/a	n/a	Gas
CUTE Barcelona [1]	Electrolysis	n/a	n/a	Gas
CUTE Hamburg [1]	Electrolysis	n/a	n/a	Gas
ECTOS Rekyjavik [1]	Electrolysis	n/a	n/a	Gas
UNST Scotland [1]	Electrolysis	n/a	n/a	Gas
CRES, Greece [3]	Electrolysis	n/a	n/a	Gas
BP Singapore [3]	Electrolysis	n/a	n/a	Gas
Munich airport [5]	SMR	n/a	n/a	gas
Munich airport [5]	Electrolysis	n/a	n/a	gas
Expo 2000, Toho, Japan [2]	SMR	n/a	n/a	Gas
AC transit Oakland [4]	SMR	n/a	n/a	Gas
Osaka Gas, Japan [2]	SMR	n/a	n/a	Gas
Crane, Indiana USA [3]	Electrolysis	n/a	n/a	Gas
Las Vegas, Nevada, USA [3]	SMR	n/a	n/a	Gas

**Table 6-1 Pathways used in projects worldwide**

Key:-

[1]. For further details refer to chapter 5

[2]. JHFC hydrogen project web site <http://www.jhfc.jp/e/station/kansai/osaka/index.html>

[3]. (Fuel Cells 2000, 2008)

[4]. (AC transit Oakland, 2010)

[5]. (IEAHIA, Unknown)

[6]. (NREL, 2008a)

Of the projects identified, only two production methods are used. Centralised production methods appear to use SMR production and transportation by road only. However the choice of transport medium (liquid or gaseous hydrogen) appears to be evenly spread, implying that there is no obvious choice for final pathway selection.

## 6.2.2 Pathways used in this research

In chapter 1, hydrogen was portrayed as a flexible fuel (or energy carrier) in the way it is produced, transported and used. There are many permutations of possible pathways from production to end use. Whilst most are technically feasible, some may be impractical or illogical from either an energy efficiency or environmental point of view (e.g. minimised emissions). Table 6-1 identified that only four or five of these pathways have been demonstrated so far, and allowing for the fact that the survey was not exhaustive, it is reasonable to assume that; very few of the potential pathways have yet to be fully demonstrated. Given the likely costs of trialling different pathways, perhaps this is not too surprising.

### 6.2.2.1 Potential Pathways

The easiest way to determine potentially viable pathways is to identify all possible pathways, then to eliminate the ones which are unlikely to be feasible. Allowing for only the most common methods of production (including location), state and transport method we have:-

- Production locations = 2 (centralised and localised)
- Most viable types of production = 4 (SMR, electrolysis, biomass, thermal separation)
- Hydrogen state = 3 (gas, liquid, solid)
- Transport method = 3 (road, rail, pipeline)

These permutations can be expressed as:-

Total options = Centralised options + Locations options

**Equation 1 = (centralised \* production type \* hydrogen state \* transport method) + (localised \* production type \* hydrogen state)**

$$= (1*4*3*3) + (1*4*3)$$

$$= 36 + 12$$

$$= \underline{48}$$

Whilst it is possible to model this number of pathways, some are technically impossible (eg: solid state hydrogen by pipeline) it is possible to reduce the figure significantly if we exclude these unrealistic options.

### 6.2.2.2 Initial exclusions

In chapter 3 and 4, thermal separation was summarised as having complex technology and only suitable for large scale, centralised production. Due to the heat input required this is only likely to be viable if a significant amount of heat is available from a source such as a nuclear power station. Whilst nuclear power is currently favoured at the time to writing, it is reasonable to assume that for

the foreseeable future, hydrogen is unlikely to be produced by this method. Furthermore, there are only likely to be a small number of nuclear power plants in the UK, often located some distance from population centres (by design) and hence would involve longer delivery distribution networks to deliver the hydrogen to the most likely point of use.

In chapter 3 and 4, solid state hydrogen was identified as a possible future source of hydrogen storage. It does however have a number of drawbacks, which were highlighted by experts and which need to be overcome, before it is likely to be a viable part of any hydrogen pathways. Currently it doesn't meet target storage densities and it has technical challenges associated with charging and discharging. Even if these challenges were overcome, it is not clear what type of pathway solid state hydrogen would require. For example it may be that solid state hydrogen is only suitable for on board storage. It may be that the Calor gas scenario<sup>25</sup> will apply and there will be no need for a hydrogen specific distribution system at all.

In chapter 3, biomass was identified as being mainly for large scale (and hence centralised production). Maximum demand for a single bus fleet would need only 5,000 kg/day. A typical biomass plant capacity exceeds this and localised production generally needs supply to match demand.

Whilst it may be technically possible to build small scale biomass production plants, similar to the small scale reformers used in CUTE they have several disadvantages when compared to SMRs. An SMR only requires feedstock & utilities which already have a distribution network (natural gas, water, electricity etc.), whereas the feedstock for biomass would need to be delivered specially, by truck and possible disposal of waste residue. Considering that this research is focusing on fleet vehicles with a single point model (rather than a network) it is reasonable to exclude biomass as an option for localised production. If we now return to Equation 1 and exclude the options discussed we now have:-

**Equation 2 = (production \* hydrogen state \* transport method) + (production \* hydrogen state)**

$$\begin{aligned} &= (1*3*2*3) + (1*2*2) \\ &= 18 + 4 \\ &= \underline{22} \end{aligned}$$

<sup>25</sup> Refer to chapter 3 for further explanation.

### 6.2.3 The final exclusions and pathways selected

The twenty two pathways can now be listed as shown in Table 6-2, and it is possible to reduce this still further (refer to exclusion notes).

Pathway	Method	Produced as	Transport method	To be modelled	Reasons for exclusion
C1	SMR	Gas	Road	Yes	
C2	SMR	Gas	Pipeline	Yes	
C3	SMR	Gas	Rail	No	1
C4	SMR	Liquid	Road	Yes	
C5	SMR	Liquid	Pipeline	No	2
C6	SMR	Liquid	Rail	No	1
C7	Biomass	Gas	Road	Yes	
C8	Biomass	Gas	Pipeline	Yes	
C9	Biomass	Gas	Rail	No	1
C10	Biomass	Liquid	Road	Yes	
C11	Biomass	Liquid	Pipeline	No	2
C12	Biomass	Liquid	Rail	No	1
C13	Electrolysis	Gas	Road	Yes	
C14	Electrolysis	Gas	Pipeline	Yes	
C15	Electrolysis	Gas	Rail	No	1
C16	Electrolysis	Liquid	Road	Yes	
C17	Electrolysis	Liquid	Pipeline	No	2
C18	Electrolysis	Liquid	Rail	No	1
L1	SMR	Gas	-	Yes	
L2	SMR	Liquid	-	No	3
L3	Electrolysis	Gas	-	Yes	
L4	Electrolysis	Liquid	-	No	3

Table 6-2 Potential hydrogen pathways to be modelled

**Exclusion Notes**

1. Rail has been excluded for simplicity. Transport technology is similar to road transport for both gas and liquid state. The choice of road or rail is largely dependent on locality to a suitable rail network. Even then, it is difficult to foresee that it would be economic, except when the gas fleet refueling depot was located adjacent to a rail terminus. Whilst this may be a solution for an integrated hydrogen network it is not considered further here. This excludes pathways C3, C6, C9, C12, C15 & C18)
2. This option has been excluded because it is technically difficult to transfer liquid hydrogen long distances by pipeline due to heat gain in the cryogenic fluid. It would vaporize unless excessive sub-cooling is carried out. This excludes pathways C5, C11 & C17)
3. The current bus fleet on board storage medium is gaseous hydrogen. All hydrogen is produced in gaseous state and as localized production does not require transportation, liquefaction of the hydrogen for local storage can be considered unnecessary. This excludes pathways L2 & L4.

This now reduces the number of pathways to be modelled down to nine centralised pathways and two localised pathways. This encompasses all the pathways demonstrated so far, as identified in Table 6-1 plus the two new options of the use of biomass to produce hydrogen, and also transporting of hydrogen by pipeline.

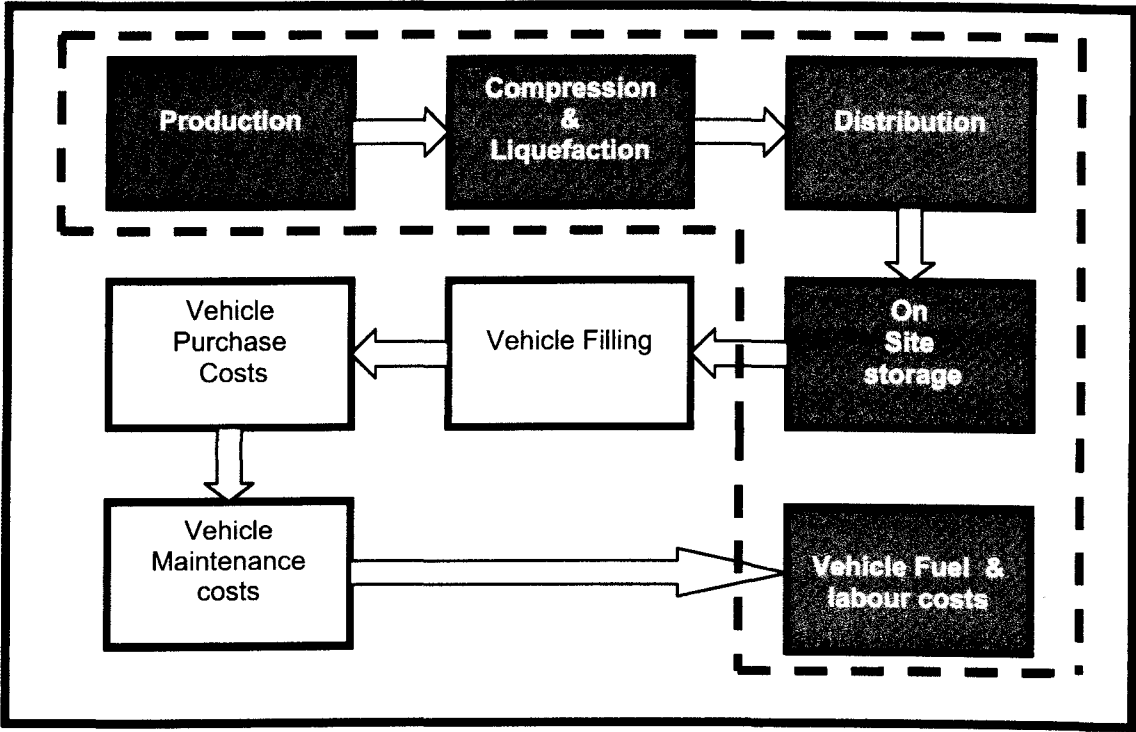


## 6.3 Model overview

Having justified the approach to modelling in section 6.1 and the pathways to be modelled in section 6.2, The model requirements can now be summarised as:-

- A Single point distribution model.
- Applied to fleet vehicles (buses) which can be adjusted to take into account fleet size, distance travelled, and operating parameters etc. including fuel economy.
- To allow for variations in energy costs and emissions of natural gas, electricity and biomass.
- To allow for variations in both capital and operation costs of production, transportation and storage methods.
- To include all three selected production methods, two fluid states, and transportation either by road or pipeline.
- To calculate both costs and emissions for all selected path ways, based on demand (hydrogen requirement) and supply chain length.
- To be compared with a base case diesel bus fleet, with the option to input both the cost of diesel and fuel consumption.

Figure 6-1 defines the boundary of the model. Although it models the distribution system it includes the performance of the vehicle as different fuels are considered (hydrogen and diesel) as well as different “engine” technologies (ICE in the case of diesel and FCV in the case of hydrogen). The components excluded are primarily related to the costs and operation of the vehicle. The cost of refuelling dispensers has also been excluded from the model. According to the US DoE delivery analysis spreadsheets, typical refuelling dispenser capital costs are £0.12/kg for liquid hydrogen and £0.05/kg for gaseous hydrogen (US DOE, 2009). The costs on a per kg basis are highly dependent on the CAPEX life and utilisation (ie: how many buses per dispenser). For example the three buses in the CUTE project in London would equate to approx 17p/kg for liquid hydrogen dispensers, based on typical demand. If the dispenser utilisation is optimised (ie: a significant number of buses per filling dispenser, the costs would be significantly less. Since the US DoE figures are relatively small it is considered acceptable to exclude these costs from the model. However, the cost of compression (both capital and energy costs) have been included.



**Figure 6-1 Model boundaries**  
(Contained within red dotted line)

## CHAPTER 7 MODEL DESCRIPTION

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The main purpose of this chapter is to:

- Introduce the model used in this research;
- Provide an understanding of how the model works;
- Indicate what inputs are required and what outputs can be expected.

For readers interested in an overview of this model, this chapter should provide sufficient information to have an understanding of the model and what can be expected from it. For ease of reading, the detailed information has been included in Appendix 4 which is intended for readers interested in the “mechanics” of the model, including all the sources of “fixed data”, such as compression and pipeline calculation methods. The appendix is in effect a user manual to aid, both the reader of this research, and users of the model to have sufficient information to understand the model functions and to operate in a way that will produce meaningful results.

### 7.1 Development

The model has evolved during the course of this research from a simple spreadsheet, intended to carry out calculations for the author; into a relatively user friendly tool. Originally, data was included within calculation cells completely contained in one spreadsheet. This made the model difficult to change and also subject to undetected errors when making changes.

An input sheet was added so that a user could input all the data in a separate worksheet with recommended values to guide the user where appropriate. This was tested by users with different levels of knowledge about hydrogen supply systems. Two of the users were my supervisors; the feedback concluded that the sheet contained a significant number of inputs, which required varying degrees of knowledge to use. As a consequence, it was decided to divide the inputs sheet into two sections. A basic level “user interface sheet”, and a more complex “inputs sheet” intended for more advanced users. An example of a basic input would be perhaps fleet size, an example of a complex input would be perhaps the cost of carbon capture and storage. In these two examples almost any user could determine fleet sizes, but a certain amount of expertise would be required to have knowledge of typical carbon sequestration data. This enabled basic and advanced users to operate the model more easily. Apart from making the model more user friendly, the changes to the model provided three other benefits:-

1. The original model was not flexible, in that any changes required significant amounts of manipulation in the spreadsheet. For example, just changing base costs for hydrogen liquefaction required various formulae to be modified.
2. The mathematical functions of the spreadsheet were checked independently by a colleague with experience of spreadsheets, in particular Excel. The brief was to review all formulae used in the spreadsheet to ensure correct mathematical functions and cross references to other cells and worksheets. This included the various “if” / “and” commands often used to sort and select results from data cells. In addition functions such as look up tables were checked, although the visual basic programming used for functions such as selection of CCS were not independently checked. Although programming required can be complicated, the function was only used to select between cells and therefore easy to verify.. In its existing form this was a difficult task, as formulae and input data were embedded in the same cells. Furthermore, every change defined in (1) above required the whole model to be re-validated. The current version does not require formulae to be validated unless that particular calculation module has changed (see Figure 7-1 for explanation).
3. The increased flexibility meant that the model can more effectively be tested against the work of others. It is an important aspect of modelling to test the accuracy and robustness against other, independent results.

The model improvements helped both the author and hopefully any user to model to produce results easily, although output data handling requires some manual manipulation.

Another important modification was to provide the facility to adjust tanker delivery speeds to improve accuracy. The requirement to include this level of accuracy in the model was highlighted during tests carried out between the research model and the US DoE model in the model testing which is reported on later in this chapter.

Further development work involved amendments to the operating data for the production facilities. Although the initial comparisons were reasonable (when the same costs for energy were used), there were two specific areas that the research model needed to be adjusted. Firstly, the OPEX costs appeared to be too generic and an adjustment needed to be made to compensate for the variations in the processes. The author concluded that it was reasonable to assume that a simple process such as electrolysis would have lower OPEX costs than perhaps a natural gas SMR. This was achieved by allowing manual adjustment of the OPEX costs in the production work sheet.

Secondly, the research model did not take into account utility costs and although a relatively small percentage of the overall energy costs, it did improve accuracy. For further information, refer to Appendix 4.

## 7.2 Model description

The model is best described in schematic form as shown in Figure 7-1, further details on the actual inputs / outputs and how the calculation modules work, can be found in Appendix 4.

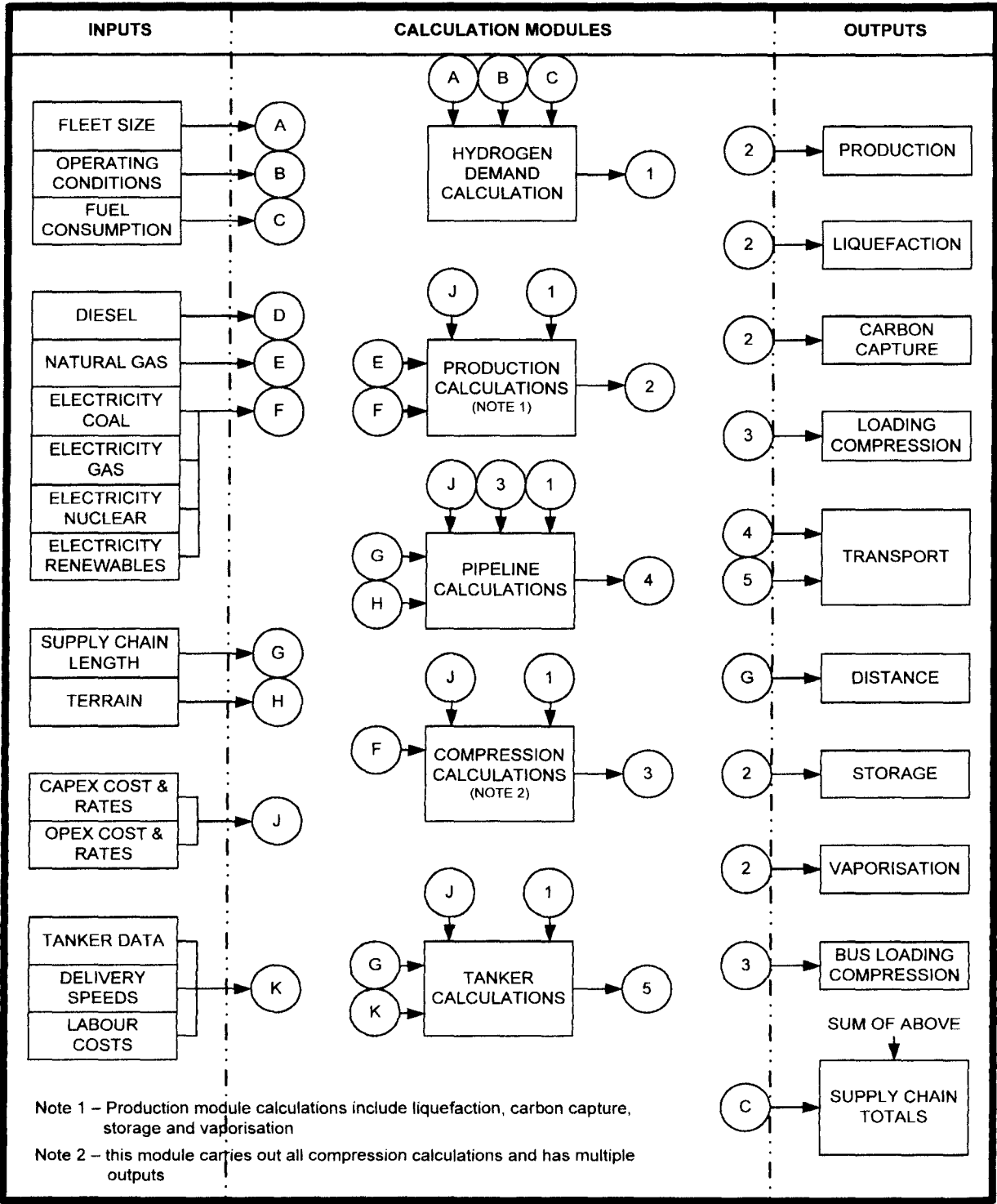


Figure 7-1 Simplified Input / Output diagram of model

The model consists of five worksheets combined into one workbook, using Microsoft's Excel, spreadsheet program. Each worksheet is described in detail in Appendix 4. The five worksheets are:-

1. Cover sheet and notes (for explanatory notes and version control)
2. User Interface worksheet (base level inputs)
3. Inputs worksheet (advanced level inputs)
4. Outputs worksheet (an overview in graphical form)
5. Results worksheet (detailed results of each step of the supply chain)

The model draws on data from a wide variety of sources, but data on the vehicle fuel consumption is sourced from the CUTE project. It takes the average of the twenty seven buses in nine cities with different operating conditions to give an average fuel economy of  $0.25 \text{ kgH}_2/\text{km}$ , which is used for all calculations in the model. Since the CUTE project, there have been a number of other bus trials and as with most new technologies there have been improvements in efficiency. For example, an FCV bus trial by the Sun Line Transit Agency reported a fuel economy figure of  $7.14 \text{ mile} / \text{kg H}_2$  ( $0.09 \text{ kgH}_2/\text{km}$ ). This represents a significant improvement in fuel economy (NREL, 2009). Whilst the fuel economy used in the model is important when comparing with the diesel base reference it has no effect on comparing the hydrogen pathways against each other. To aid the user, the model has been designed with colour coded cells, to identify the input cells which are user changeable as well as "advisory" values in adjacent cells. In a few cases, visual basic programming has been used. Select buttons are used to change a number of cells which would be affected; for example the option to include for carbon capture and storage. Another user aid is the use of comments inserted in cells where it is felt that further explanation is needed.

It should be stressed that a desirable function of any hydrogen supply chain is that supply should as far as practicable match demand. This is particularly important for the liquid supply chains to avoid excessive losses due to hydrogen "boil off" (as found in the CUTE project). At present, the model does not include an allowance for such losses, this is in keeping with the diesel supply chain which also assumes zero losses due to 'evaporation'.

This model considers hydrogen bus fleets in isolation. It does not consider the transition from conventional diesel to hydrogen powered FCVs. It is recognised that any bus fleet transition is likely to be gradual and would also impact on the issue of supply matching demand. As old buses are replaced by newer hydrogen powered FCVs the hydrogen requirements would increase. This



would not significantly impact the centralised production methods but would affect the choice of the hydrogen production equipment. This transition is not considered in the model results.

Finally, although the pathways in the outputs are fixed in the model (based on the likely viable pathways selected in chapter 6), it is possible, to modify the outputs for almost any type of supply chain. This could include solid state hydrogen distribution for example, although this is considered outside the scope of this research modelling.

### **7.3 Input worksheet sheets**

The two inputs sheets have already been defined as “basic” (user interface sheet) and “advanced” (inputs sheet) respectively. Examples of these inputs are shown in Figure 7-1. Inputs A to H are “base level” inputs, which can be varied to enable the user to easily calculate “what if” scenarios. This might be, for example, by varying fleet sizes, supply chain lengths, basic energy costs, fuel efficiencies etc. The second “advanced level” inputs sheet requires the user to have an understanding of hydrogen supply chains, for example capital and operating costs of equipment etc. Typical examples of these inputs are shown in Figure 7-1 (inputs J & K).

Due to the complexities of modelling production costs and emissions, it was necessary to add a third input sheet named “production”. It is mainly designed to calculate production costs and of interest only to readers who wish to understand the detailed methods of calculation hydrogen production data.

### **7.4 Output and results worksheets**

Cost and emissions results reported are shown in Figure 7-1. Results are left in the raw state for copying and pasting into other documents to produce more meaningful results, such as graphs etc. This is best explained by the following example:-

If the user wants to vary the supply chain length for a fixed set of energy costs, they are required to manually change the length and copy each set of results, increasing the supply change length manually by increments as required. This may appear to be unnecessarily labour intensive, but given the number of potential variables (more than 25 on the basic user sheet alone), it is felt that automation of these increments would have added significant complexity, at the same time as reducing flexibility of the model.

## 7.5 Model approach to costs

The purpose of this model is to calculate and compare the costs and emissions of various hydrogen pathways against each other and a base diesel reference case. Although it needs to calculate costs, it is not intended as an economic or investment planning model. For this reason, a simplistic approach has been taken with respect to the methods and approach to calculating costs. It is recognised that this could lead to some inaccuracy in results which will be quantified here and used to justify this approach. These costs can be divided into capital and operating costs. The terms CAPEX and OPEX will be used and are explained in the glossary

### 7.5.1 Capital costs

Equipment costs in this research model have been reported in two different ways. Firstly, simple systems such as storage tanks and vaporisers have source data directly inputted in the model, on the basis of cost per kg of hydrogen. Sources are defined in Appendix 4. Secondly, other equipment such as a process plant, compressors and pipelines have the direct capital cost of equipment inputted into the model and it is then calculated in terms of cost per kg of hydrogen.

This section will focus on the latter, and the possible effects on accuracy of the data in question. Before reviewing the accuracy of this data used, two points need to be clarified. The term CAPEX is used to define the expected operating life of the equipment; it is not necessarily the same time period that would be considered for any loans to purchase capital equipment. The second point relates to the rate of inflation which is used as 2% per annum, this is not necessarily the same rate that would be used to calculate any loans to purchase capital equipment.

The data sources for the cost of equipment have been detailed in Appendix 4 and the effect on the accuracy of this data is addressed in the sensitivity analysis in section 7.6.2. This comparison focuses on finance aspects of the purchased equipment. As stated earlier, the model takes the simplistic approach that the equipment is purchased on day one for the project without consideration of where finance may come from. The effects shown here are reported on the basis of additional costs to the pathway and are significantly less than the additional cost of the production equipment for reasons described above.

#### Loan repayment comparison

One could argue that it should be calculated on the basis that the capital is borrowed and repaid over a fixed period of time. The problem with this approach is that it requires a rate of interest and loan period to be applied. Whilst this is possible, it would normally be considered on the basis of

some income (sales of hydrogen), this would in effect, convert the model into an investment analysis tool. It would require an estimate of loan period , interest rate, as well as projected sales to be able to repay the loan. All of which add uncertainty to a model. Although not considered a realistic approach for this model, the effects have been calculated on the basis of an arbitrary rate of 7%per annum and a loan period of 10 years without consideration for ability to repay this loan (ie sales).

The effect on each pathway varies according to the overall percentage of capital purchased equipment compared to other costs such as energy. Analysis of the pathways shows an average cost increase of 7%, although the localised pathways were more significantly affected at between 12 to 15%.

### **Interest on investment comparison**

Another method is to assume that the capital is available and to identify what it would be worth if it had been invested for the period of the project rather than used to purchase equipment. Each item was calculated on the basis of its CAPEX life with an interest rate equivalent to the inflation rate used. Again, the latter figure is arbitrary, as interest rates would vary over this period, so this can only be considered an approximation. Analysis of the pathways shows an average cost increase of 3.7%. Again, the localised pathways were more significantly affected but to a lesser extent (between 6% to 8%).

### **Net Present Value (NPV)**

Net Present Value is a calculation method used in investment project analysis to evaluate the viability of projects using methods such as Discounted Cash Flow (DCF) techniques. It is not proposed to explain the principle in detail here. For further reading and explanation on this topic refer to a typical text book on this subject such as "*Investment Mathematics*" (Adams A et al., 2003).

Although this method is used for investment analysis and the problems of applying this approach to this model have been discussed earlier. It is still worth comparison. The formulae used in this comparison is taken from "*Energy systems and sustainability*" (Boyle G et al., 2003) and is:-

$$A = V_p \times r \times [1-(1+r)^{-n}] \text{ (Boyle G et al., 2003, p497)}$$

Where

- A = Annuitized value
- $V_p$  = Present value (Capital cost of equipment)
- r = interest rate (inflation rate)
- n = Number of years (CAPEX life)

To calculate the total cost of the equipment based on NPV, the Annuitized value is multiplied by the CAPEX life. It is recognised that the interest rate may not represent a true loan rate but this is for comparison purposes only.

Based on the above methods the average cost increase is about 3.7%, although the maximum variation is again the localised production methods (between 5.5% and 7.5%). It appears to have minimal effect on some pathways such as centralised electrolysis (<2%), due to the fact that electrolysis is an energy intensive process and hence energy costs represent a high proportion of the overall pathway costs

7.5.2 CAPital EXpenditure operating life (CAPEX)

Since the model calculates hydrogen costs on a £/kg basis and all equipment has a practical limit of operation in terms of time scale, an estimate of the working life of the equipment is necessary to enable the calculation to be made. The CAPEX life is expressed in years and is likely to vary according to equipment type. The model enables the user to vary this figure based on equipment type, eg: pipelines and compressors. It is reasonable to assume that compressors being moving pieces of equipment are likely to have a shorter practical operating life<sup>26</sup> than a static installation such as a pipeline. Varying the CAPEX life for different pieces of equipment does not create inaccuracies in the model as costs for hydrogen are on £/kg basis. The following examples explain the principle:-

Example A		
	Compressor	Pipeline
Capital cost (£)	250,000	2,000,000
CAPEX life (yrs)	25	50
Capacity (kg/day)	1,000	1,000
Formulae	Cost £	
	-----	
	CAPEX life (yrs) x capacity (kg /day) x 365 days / yr	
Cost £/kg	0.027	0.110
Total cost £/kg	0.137	

<sup>26</sup> Theoretically, equipment can be operated indefinitely with the appropriate maintenance. But over time these costs increase and often efficiency decreases until it is more viable to invest in new equipment. It is this point that is considered as the CAPEX life of the equipment.

It could be argued that CAPEX life differences would cause errors in the calculation, but as the calculation is based on cost / kg of hydrogen these cancel out when a second compressor is added as shown in example B:-

Example B		
	Compressor	Pipeline
Capital cost (£)	250,000 + 250,000 = 500,000	2,000,000
CAPEX life (yrs)	25 + 25 = 50	50
Capacity (kg/day)	1,000	1,000
Formulae	<div>Cost £</div> <div>-----</div> <div>CAPEX life (yrs) x capacity (kg /day) x 365 days / yr</div>	
Cost £/kg	0.027	0.110
Total cost £/kg	0.137	

Of course this does not take into account inflation when having to purchase a 2<sup>nd</sup> compressor after 25 years. In this case, assuming inflation at 2% per annum, the cost for the 2<sup>nd</sup> compressor would be approximately £410,000. In which case the example would be:-

Example C		
	Compressor	Pipeline
Capital cost (£)	250,000 + 410,000 = 660,000	2,000,000
CAPEX life (yrs)	25 + 25 = 50	50
Capacity (kg/day)	1,000	1,000
Formulae	<div>Cost £</div> <div>-----</div> <div>CAPEX life (yrs) x capacity (kg /day) x 365 days / yr</div>	
Cost £/kg	0.036	0.110
Total cost £/kg	0.146	

In example C the cost increases, but not significantly as the pipeline is likely to be the largest and hence dominate cost factor. Of course this difference would vary as the ratio of pipe line to compressor costs vary but is not considered significant and justifies the simplistic approach used in this research.

### 7.5.3 Operating costs (OPEX)

Operating costs can defined in a number of ways. One common method is split them into fixed and variable costs. The split between these costs are fairly arbitrary and can vary according to the equipment design, operating conditions and accounting practice of the organisation in question. A typical split could be:-

Fixed Costs		Variable costs	
1.	Maintenance (labour and materials)	1.	Raw materials
2.	Operating labour	2.	Miscellaneous operating materials
3.	Laboratory costs	3.	Utilities
4.	Supervision	4.	Shipping and Packaging
5.	Plant overheads		
6.	Capital charges		

7. Rates (and any other local taxes)
8. Insurance
9. Licence fee

Source: (Sinnot RK, 2005, p260 - 261)

### **Fixed operating costs**

The approach used in this research model is to define the fixed operating costs (OPEX) as an annual percentage of the capital cost of the equipment in question. The model enables the user to vary this figure based on equipment type, eg: pipelines and compressors. It is reasonable to assume that compressors being moving pieces of equipment are likely to have an annual maintenance costs which are higher than a static installation such as a pipeline. For example, if the capital cost for a compressor was £100,000 and the OPEX rate was 5%, the model would allow for £5,000 per annum towards the overall cost of hydrogen on a £/kg basis.

### **Variable operating costs**

The variable operating costs for this model in terms of production processes are mainly limited to raw materials (such as feedstock) and utilities (such as electricity), in other words items 1 & 3 of the variable costs defined above. These are calculated according to requirements in the model and vary according to each process and equipment. For example compression variable costs are limited to electricity required for motive power, an SMR may require natural gas as feedstock and electricity as a utility.

The only area that this research model approach varies with the definition by Sinnot is in the use of road tankers to deliver hydrogen, whereby the driver labour costs and fuel used are calculated as part of the variable costs. In the above definition labour costs are considered part of the fixed costs (item 2). The reason for this variation is that these costs are dependent on supply chain length.

## **7.6 Model testing**

Previously, the focus was on how the model was constructed, where data was sourced from and an explanation of how the model works. Having built the model, a degree of checking and testing was required to ensure that the model is robust and able to produce meaningful results. Some of this work was carried out by persons other than the designer of the model. Where appropriate, credit for this work is acknowledged in this section. To do this, it is necessary to:-

- 1) Validate formulae used
- 2) Carry out sensitivity analysis to see how the outputs are affected by changes in key data
- 3) Test outputs such that the model behaves in the way expected
- 4) Test against other results



### 7.6.1 Validation of formulae

Although the model is not particularly complicated mathematically, it does use some of the basic mathematical functions available in Excel (e.g. calculations for compressor power). It also uses “look up” tables and logical functions such as “if” statements within cells. For these reasons it is important to have confidence that model is mathematically correct. It was also important that this check was carried out by an independent person, although, not necessarily with any specific knowledge of hydrogen supply systems.

The brief was to review as many cells as possible which contained formulae or logical statements etc. To check specific cells which had “engineering or scientific type” calculations to ensure they were mathematically correct and appropriate. It did not include a requirement to check the basic data such as production costs etc. as these have been referenced within this research and can be independently verified if necessary. The checking was carried out by a colleague, Luke Rubens<sup>27</sup>.

### 7.6.2 Test – Sensitivity analysis

Sensitivity analysis in this context involves testing the input variables to the model to see what effect variations have on the output results. This test looks at how the results vary for a given range of inputs. It was decided to test for variations of +/- 25% to the input value; the main reason for this is the stated accuracy of the pipeline modelling tool. The other area where significant variations in cost have been reported in this thesis is the cost of production. Since the production cost data used in this model comes from a variety of sources, it is reasonable to assume that the values used in this model are reasonably accurate, certainly within the +/- 25% margin of error tested here. Most other inputs are considered reasonably accurate in the model and hence should all fall within the current margin of this test.

These tests are limited to costs only as these have the greatest uncertainty within the model. In general the emissions used are reasonable well defined and cited from reputable sources. The main contributors are electricity generation and emissions from processes such as steam methane reforming, both of which have been researched. The largest variation is likely to be associated with changes of energy mix for electricity generation, which is calculated in the model based on the contributions of each of the energy sources such as coal, gas etc.

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<sup>27</sup> Luke Rubens is a graduate project engineer with experience of working on natural gas pipelines and compression systems and specific skills in the use of databases and spreadsheets.

The tests have been limited to variables that are largely fixed for the analysis work carried out in chapters 8 & 9. The results reported here can be used to assess the margin of error in the results of chapter 8 & 9.

For reporting purposes the results of these tests are shown on the basis of +/- variation on the norm in terms of percentage effect on the overall costs. Most cost increases give an increase in the output, although some have the reverse effect. For example reducing tanker delivery speed actually increases cost, and vice versa. Ten test were carried:-

<b>Test No.</b>	<b>Test variation description</b>	<b>Min (-25%)</b>	<b>Max (+25%)</b>
1	Average tanker speed	+4.2%	-2.5%
2	CAPEX life	+2.9%	-1.8%
3	OPEX costs	-2.6%	+2.6%
4	Production capital costs	-8.4%	+8.4%
5	Storage capital costs	-6.7%	+6.7%
6	Pipeline costs	-7.2%	+7.2%
7	Tanker capital costs	-1.5%	+1.5%
8	Tanker loading / unloading times	-0.5%	+3.5%
9	Tanker driver labour costs	-2.0%	+5.00%
10	Tanker utilisation	+2.4%	-1.5%

The values shown are the max / min for a specific pathway in each test and not indicative for all pathways in that test. For example, the +/- 8.4% reported for production capital costs, are for localised production by SMR, the centralised equivalent variation is only +/-1.5%. The largest margins are based on the costs of production, pipelines and storage all of which are investigated in chapter 8.

### 7.6.3 Test – output testing

Output testing in this context is defined as testing that the model behaves in the way expected for a given set of conditions. For example it would be reasonable to assume that if supply chain length and hydrogen demand increased, pipeline pathways would show benefits over road transport methods. Although the complete pathway from production to end use is modelled, it is possible to carry out sensitivity analysis on parts of the pathway such as supply chain, due to results in the results worksheet being reported for each step of the pathway.

The purpose of this test is to ensure that transportation costs increase in line with expectations. It should not be read as a true test of costs, but as a test of consistency in the way that costs should increase. Figure 7-2 shows four pathway costs. High demand is based on 5,000 kg per day and low demand is based on 500 kg / day. All other variables were fixed. Electricity was set to UK average mix and cost, and diesel costs were £1.10 per litre.

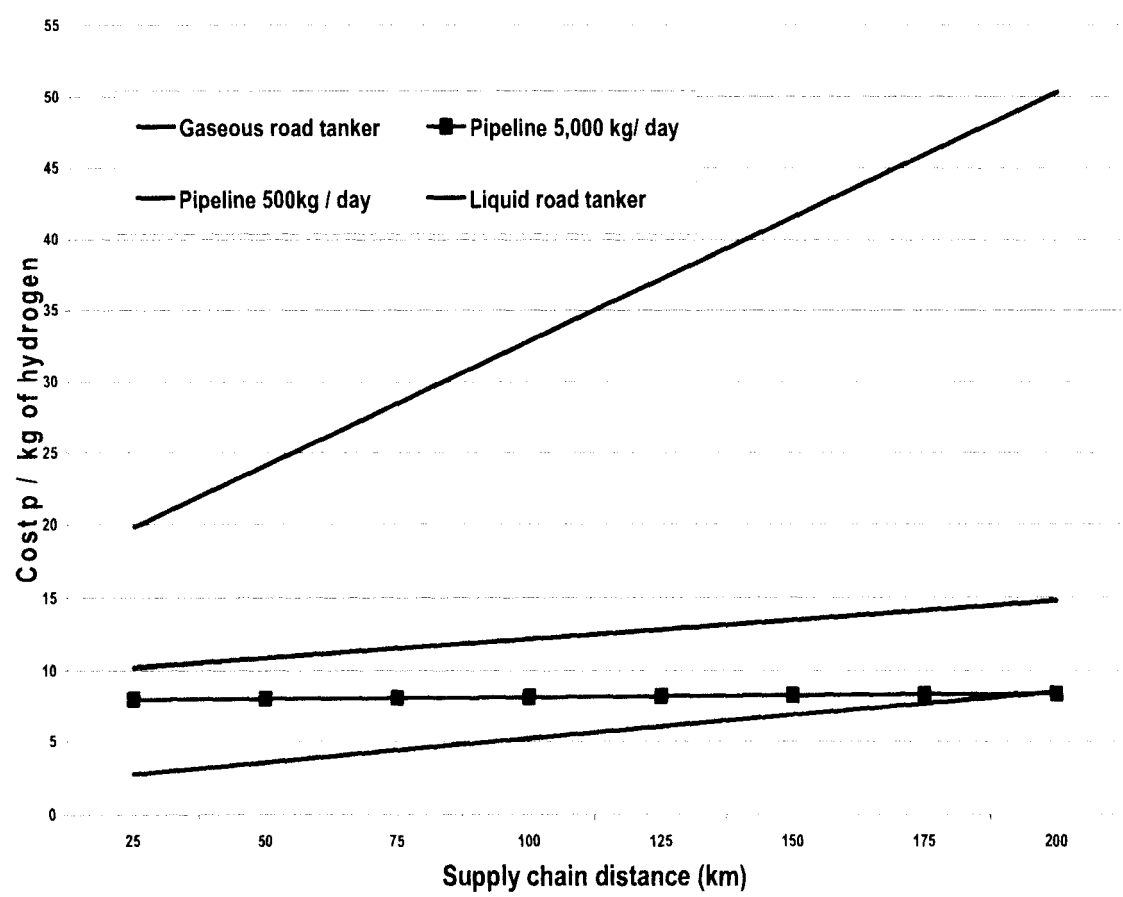


Figure 7-2 - Transportation costs

The results in Figure 7-2 are purely for comparison purposes only and do not reflect the actual costs to transport hydrogen. Liquid hydrogen by road did not include the cost of liquefaction and gaseous hydrogen by road did not include the cost of compression. Pipeline costs did include compression as it is, in effect, the transportation method.

Pipeline costs results were as expected with low demand being more expensive than high demand, although not particularly sensitive to demand. This is as expected as significant amounts of hydrogen can be carried in relatively small bore pipelines.

Road tanker costs for both liquid hydrogen and gaseous hydrogen increase with distance but are not particularly sensitive to demand once a minimum is reached, hence only one set of figures are reported. As expected, gaseous hydrogen is more expensive than liquid hydrogen and the cost

differential increases with distance. This is consistent with the fact that gaseous hydrogen tanker carrying capacities are significantly less than liquid hydrogen tankers as reported earlier.

#### **7.6.4 Test – comparative testing**

One logical starting point for is to test the model results against the CUTE delivery by truck hydrogen case. It is assumed that the CUTE trucked in hydrogen is produced by the Steam Methane Reforming (SMR) process. Although the CUTE project does provide a break down of the costs (refer to Chapter 5), it is not particularly detailed, or reported in the same format as this model; so detailed analysis of the steps are not worthwhile. Also, the supply chain length is not stated, but assumed to be in the region of 200km. The comparison costs (per kg of hydrogen) are:-

- CUTE hydrogen delivery by truck total cost range £5.34 to £21.35<sup>28</sup>
- Model pathway C1, SMR production, hydrogen delivery by truck - gaseous state = £2.60
- Model pathway C4, SMR production, hydrogen delivery by truck - liquid state = £2.95

Whilst there seems to be a substantial difference between CUTE and the model results, there are mitigating factors. In the CUTE project trucked delivery case, significant losses were suffered due to boil off. London losses were 69% and Porto losses 10% (CUTE, 2006, fig 2.2.9 p37). The CUTE losses are assumed to be factored into the costs above. The model assumes supply and demand are matched and hence no allowances are made for boil off losses.

The Office of National statistics quoted the value of sales of hydrogen at £1.26 per kg in 2006 (ONS, 2006), which is presumably the factory gate price. This figure is consistent with the production costs used in the model. If the CUTE factory gate price was also assumed to be in the region of £1.26 per kg (as per ONS), then the cost for the balance of the pathway would be a minimum of £4.08 per kg (£5.34 - £1.26). It is therefore likely that the CUTE costs are somewhat skewed by the losses, otherwise this would indicate that the CUTE transportation costs were excessive, ie: almost three times the cost of production.

Another useful comparative test is to compare some of the results against the US DoE model reviewed in chapter 5. Although, it is not always possible to carry out direct comparison due to the differences in the way the two models are constructed and report results, some useful comparison

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<sup>28</sup> Refer to chapter 5 for details

can be drawn. The costs and emissions of various production methods were compared (refer to Figure 7-3 and Figure 7-4). The key to the production methods are:-

- 1) Centralised hydrogen production from coal without CCS
- 2) Centralised hydrogen production from coal with sequestration
- 3) Centralised hydrogen production from grid electricity using electrolysis
- 4) Centralised hydrogen production from natural gas using an SMR without CCS
- 5) Centralised hydrogen production from natural gas using an SMR with CCS
- 6) Centralised hydrogen production using biomass gasification
- 7) Localised hydrogen production using Ethanol
- 8) Localised hydrogen production from grid electricity using electrolysis
- 9) Localised hydrogen production from natural gas using an SMR

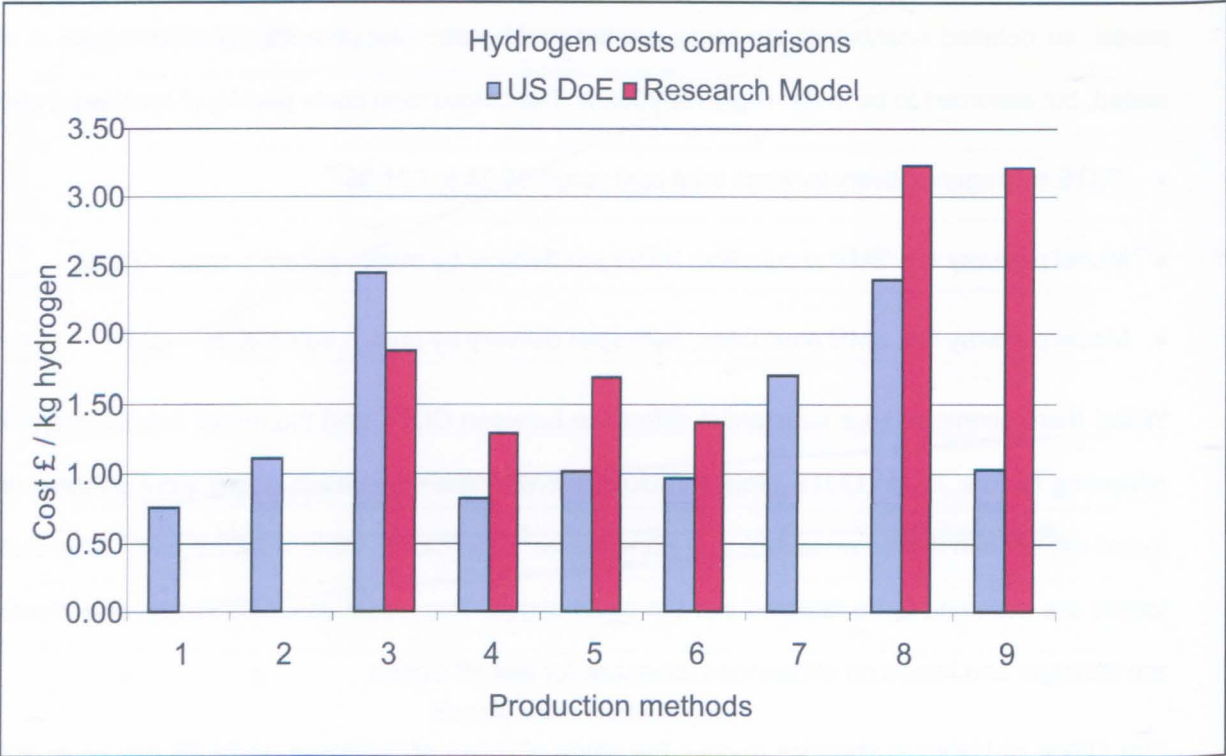
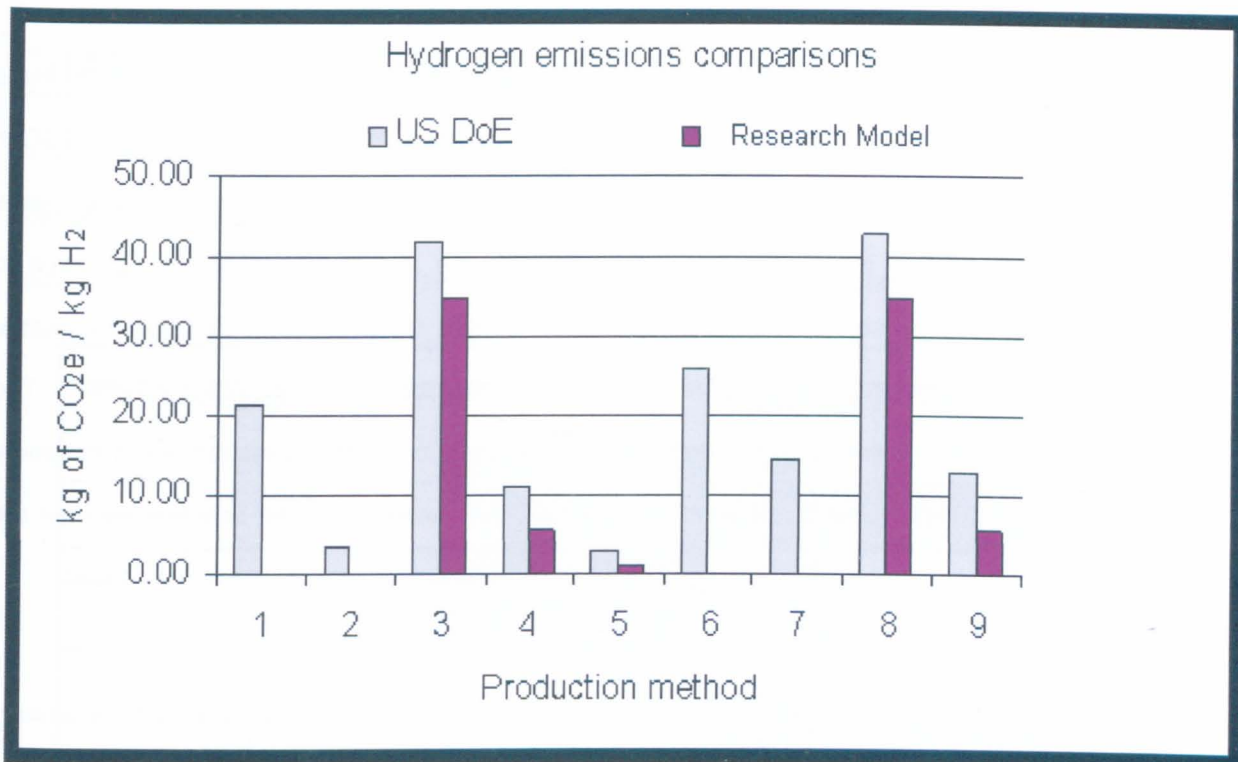


Figure 7-3 Production cost of hydrogen using both US DoE and the research models<sup>29</sup>

<sup>29</sup> Costs are adjusted for currency conversions and inflation, in line with the standard factors used in clarifications



**Figure 7-4 Production emissions comparing the US DoE versus to this research model**

It is not intended to review in detail all the variations between the two sets of results. The main points can be summarised as follows:-

- The research model does not report results from pathways 1, 2 and 7 as these are not considered in this research.
- In most cases, the research model costs are higher than the US DoE model (4,5,8 and 9), but could be considered reasonably close in most cases. No specific changes to the research model for these methods are proposed as a result of this analysis.
- The exception to this is electrolysis (3 & 8). For some reason the US DoE model reports localised production as being slightly cheaper than centralised. It also reports the US Doe being more expensive than the research model for centralised production yet vice versa for localised production.
- The emissions pathways 4 & 5 are low in the research model due to different values used. It is concluded that in this case the US DoE model is correct and hence the research model values should be changed from 5.71 to 9.28 kg of CO<sub>2</sub>e / kg H<sub>2</sub>.
- There is a difference between the carbon sequestration efficiencies assumed in the two models (83% in the research model, 90% in the US DoE model), which also affects the results in pathway 5. It is considered that a value of 90% is more realistic and hence the research model will use this value for the analysis in chapter 8.
- The emissions pathway (6), shows no emissions for the research model, this is because the biomass is considered "carbon neutral" which is perhaps an oversimplification. It would be better if specific feedstock were used a factor added to the research model for adjusting biomass "efficiency", eg: 100% assumes zero emissions.



## 7.6.5 Test – Other feedback

Apart from the other tests reported so far, the model has been used in a number of other situations to produce results. For example presentation of modelling results in conference papers at UTSG in 2008 and 2009. These included preliminary results of the analysis in chapter 8 which were presented in a similar, but abbreviated form. In 2008, the author discussed the approach to modelling and the case study review work carried out as part of this research. In 2009, the author presented preliminary results which were based on the methodology carried out in chapter 8. The author explained the results in some detail and preliminary conclusions reached. As is common, when concluding a presentation at such conferences, the author asked for any feedback on the results. To the best of the author's knowledge; no specific errors or contradictions were found.

## 7.7 Summary

Model development work has continued during the course of this research, although its primary function as a tool to calculate the cost and emissions of different supply and distribution pathways remains unchanged. As with all work of this type it has been an iterative process. Early modifications tended to focus on the structure and layout to enable ease of use. This has enabled closer scrutiny of the calculation modules such as production of hydrogen which required significant modification to better replicate accurate costs. After testing the model, further "fine tuning" was required, for example the need to be able to vary average vehicle speeds etc.

The end result of this process is a model which can now be used to model the scenarios chosen in chapter 8. Although it focuses on the specific supply and distribution pathways chosen for further study in this model, it could be adapted for other production methods (eg: Nuclear thermal diffusion) and delivery methods (eg: solid state hydrogen storage) without significant change, although such work is considered outside the scope of this research.

In Chapter 8, the model was used to investigate the key questions identified earlier in this research. Whether hydrogen supply chain costs and emissions are a significant part of the overall delivered cost and emissions of hydrogen and if so, how these vary by demand and supply chain length. It will also be used to look at how these pathways are affected by variations in energy costs and also what potential there may be for reductions in emissions, if not costs, when compared with a conventional diesel reference case.

# CHAPTER 8    MODEL RESULTS

In this chapter, the model described in chapter 7 is used to investigate a number of different scenarios associated with the production and distribution of hydrogen used for fleet vehicles (buses). The pathways previously selected for modelling are listed in Table 8-1 below for reference.

Key to pathways			
Pathway	Production method	Fluid state	Transportation method
C1	SMR	GAS	ROAD
C2		GAS	PIPELINE
C4		LIQUID	ROAD
C7	BIOMASS	GAS	ROAD
C8		GAS	PIPELINE
C10		LIQUID	ROAD
C13	ELECTROLYSIS	GAS	ROAD
C14		GAS	PIPELINE
C16		LIQUID	ROAD
DIESEL			
L1	SMR		
L3	ELECTROLYSIS		

Table 8-1 Pathways

Colour coding and hatching is the key to all diagrams used in this chapter  
eg: Blue = SMR processes.(where appropriate).

The scenarios (SC) modelled are described here. The purpose is to consider a number of linked scenarios based primarily on measurement of costs but supported where appropriate with measurement of emissions. The starting point (SC-1) is intended to report what is in effect the current situation, based on equipment / energy costs, for a given set of conditions and a fixed demand and supply chain. It then moves on to investigate how costs and emissions are affected by varying the demand and supply chain length (SC-2). Up to this point, energy costs have been fixed for all reported results in SC-1 and SC-2. In scenario SC-3 the effect of variations in energy costs are investigated. Finally, in SC-4 the focus is on emissions but supported by costs results when it considers what potential hydrogen pathways have for emissions reduction. For further explanation of variables changing in each scenario refer to Table 8-3.

SC 1 - models costs and emissions based on current technology with typical energy prices in 2008. There are a significant number of variables in this scenario; it presents a snapshot of typical hydrogen pathway costs and emissions, compared with an equivalent diesel supply chain. Initial results are reported in terms of “equivalent diesel costs”, Pathways are generally reported in terms



of cost (£ or €) per kg H<sub>2</sub> or emissions (kg CO<sub>2</sub>) per 100 km of bus travel, although when carrying out direct comparisons such as cost of hydrogen, units of £ / kgH<sub>2</sub> is used.

SC 2 - focuses on the effects of varying hydrogen demand and supply chain length in the supply and distribution system. It is focused on costs, and compares results with other research findings; it also analyses methods currently used to select optimised pathways. As this scenario focuses on the supply and distribution of hydrogen, results are also reported in terms of cost (£) or emissions (kg CO<sub>2</sub>) per kg of H<sub>2</sub>, where appropriate.

SC 3 - investigates the effects on energy costs of the selected pathways. Previous chapters have show a relatively wide variation in production cost, some of which is related to capital costs but also energy costs in the case of the more energy intensive processes. A truncated version of the demand supply chain length used in SC 2. Again, although this scenario is cost focused, emissions results are reported as this is significantly affected by variations in electricity mix. Although results are generally reported in terms of cost per 100km, the results are also reported in the more conventional form of £ / kWh, where kWh represents energy consumed during the bus drive cycle.

SC 4 – is unlike previous scenarios, and is driven primarily by overall emissions reductions and investigates the cost impact on hydrogen pathways as they move as far as possible towards an emissions free pathway. Typical sub systems used to achieve this will include the use of renewable electricity, carbon sequestration and use of FCV trucks for delivery. Results are reported using a mixture of the units of measure defined in previous scenarios.

For consistency of reading, the model variables used in each scenario are reported in Table 8-2 and Table 8-3. There are several types of numeric data used in the model:- constants, fixed variables and scenario variables. Constants are defined as fixed numerical values which remain the same under all conditions and are not reported here. A typical example would be the data and formulae used to calculate the number of compressors required for pipeline delivery. Fixed variables are numbers which are adjustable in the model but are fixed for all results reported in this chapter on modelling and are shown in Table 8-2. A typical example of this would be the capital costs of production equipment. Finally, for the purposes of clarity, all model results will be referred to in this chapter as “this research model”.

<b>Energy usage / costs</b>	<b>total</b>	<b>units</b>
Bus fuel consumption (hydrogen)	0.25	kg hydrogen /km
Bus fuel consumption (diesel)	0.37	kg diesel / km
<b>Capex &amp; Opex data</b>	<b>Capex (yrs)</b>	<b>Opex % p.a</b>
Pipelines / storage	50	2
Compressors / plant	20	5
Road tankers	25	5
<b>Production / storage data</b>	<b>Cost</b>	<b>Capacity (kg/dy)</b>
Centralised SMR	£77,940,000	379,387
Centralised Electrolysis	£52,425,000	52,300
Centralised Biomass	£62,155,000	140,000
Localised SMR	£6,218,000	4,892
Localised Electrolysis	£18,596,000	4,892
Liquefaction	£23,120,000	30,000
Carbon sequestration	£300,000,000	379,387
Purification	£500,000	9,600
Biomass efficiency	80	%
GH <sub>2</sub> storage	£0.40	per kg hydrogen
LH <sub>2</sub> LIH storage	£0.66	per kg hydrogen
Vaporisation	£0.0463	per kg hydrogen
<b>Transportation data</b>	<b>Capital cost</b>	<b>Capacity (kg)</b>
Diesel truck	£58,500	n/a
FCV truck	£310,000	n/a
Diesel tanker	£50,000	20,000
GH <sub>2</sub> tanker	£103,000	460
LH <sub>2</sub> tanker	£266,000	4,000

**Table 8-2 Fixed variables (ie: constants) used in this modelling**

The scenario variables shown in Table 8-3 vary within each scenario and are highlighted in blue. Due to the significant number of variables, to produce results which are meaningful, it has been necessary to fix some variables which may impact on the results of each scenario. Where further work is required in these cases, they will be addressed in chapter 9.

In SC1, diesel price is the primary variable investigated and it was necessary to fix the demand, supply chain length and terrain type (affecting pipeline costs and average tanker speeds) In this scenario, the maximum demand and supply chain length were chosen but with the use of 100% rural terrain. The intention was to attempt to offset the possible negative impact of demand and supply chain length against the “cheapest” delivery method as rural distribution systems allow cheaper pipeline costs and faster tanker delivery speeds.

SC2 attempts to address the issue of fixing the variables in SC1, when the primary variables become demand, supply chain length and terrain with a fixed diesel cost. In both SC1 & SC2, energy costs are fixed. In SC3 the issue of energy costs is addressed but against fixed values for

the demand, supply chain and terrain. Whilst these would affect results, further analysis of these fixed values can be carried out in chapter 9, if required. In SC4 where the emissions reduction potential of hydrogen pathways are analysed, electricity generation mix is fixed. . There is a significant variation in the emissions; depending on supply chain length. For example, in case of gaseous road tanker delivery this varies from 1.158 to 1.52 kg CO<sub>2</sub> / kg H<sub>2</sub> (31%)<sup>30</sup>. It is however, a relatively small variation when including production (less than 4%). For this reason, the supply chain demand and supply chain length have been fixed in SC4.

<sup>30</sup> Refer to appendix 5 and Figure 8-14 for details



Energy	Units	SC1	SC2	SC3	SC4
Diesel	£ / litre	1.0 - 4.0	1.00	1.20	1.20 – 3.05
Gas	£ / kWh	0.020	0.020	0.008 - 0.032	0.016 – 0.046
Biomass wood chip feed stock	£ / kg	0.080	0.080	0.040 - 0.080	0.06 – 0.14
Electricity overall cost	£ / kWh	0.064	0.064	calculated	calculated
<b>Electricity generating costs</b>					
Coal	£ / kWh	0.030	0.030	0.030 – 0.036	n/a
Natural Gas	£ / kWh	0.023	0.023	0.015 – 0.039	n/a
Nuclear	£ / kWh	0.024	0.024	0.019 – 0.024	0.01 - 0.024
Renewables	£ / kWh	0.049	0.049	0.025 – 0.049	0.01 - 0.024
<b>Electricity mix Composition</b>					
Coal	%	35.20	35.20	varied	0%
Natural Gas	%	39.70	39.70	varied	0%
Nuclear	%	20.90	20.90	varied	50%
Renewables	%	4.20	4.20	varied	50%
Electricity emissions	kg CO2 / kWh	0.52	0.52	varied	Varied
Hydrogen demand	kg / day	4,892	500 – 5,000	5,000	5,000
<b>Pipeline data</b>					
Pipeline length	km	200	25 - 200	160	160
Pipeline length % (Rural / Urban)	%	100 / 0	0 / 50 / 100%	75 / 25	75/25
<b>Production / storage data</b>					
Carbon sequestration		Not selected	Not selected	Not selected	Selected
Carbon seq efficiency	%	90	90	90	90%
<b>Transportation</b>					
Average rural tanker speed (km/hr)	km/hr	78	78	78	78
Average urban tanker speed	km/hr	46	46	46	46
Supply truck engine		Diesel	Diesel	Diesel	FCV <sup>31</sup>

**Table 8-3 Scenario variables used in this modelling**  
(Blue background highlights variables changed in the relevant scenario)

<sup>31</sup> Diesel is delivered by diesel powered trucks, hydrogen is delivered by FCV trucks



# 8.1 SC 1 – Typical pathway costs and emissions

## 8.1.1 Hydrogen Costs

One measure of the economic viability of hydrogen as an alternative “fuel” is to compare the various pathway costs against a rising cost of diesel. Figure 8-1 shows the cost of hydrogen against a varying diesel cost in the range of £1.75 to £4.00 / litre of diesel with the cost equivalent point<sup>32</sup> for each pathway shown where the diesel line crosses each pathway. It is clear from the diagram that the most economical pathways depend on hydrogen being produced by either steam methane reforming or biomass using woodchip as a feed stock. However an equivalent cost of diesel for the cheapest pathway, (C2) requires the diesel forecourt price to reach £1.75 / litre. It would appear that for the foreseeable future, hydrogen produced from electrolysis (C13, C14 & C16) is likely to be uneconomical, requiring diesel to reach a minimum of £3.25 / litre to be cost equivalent.

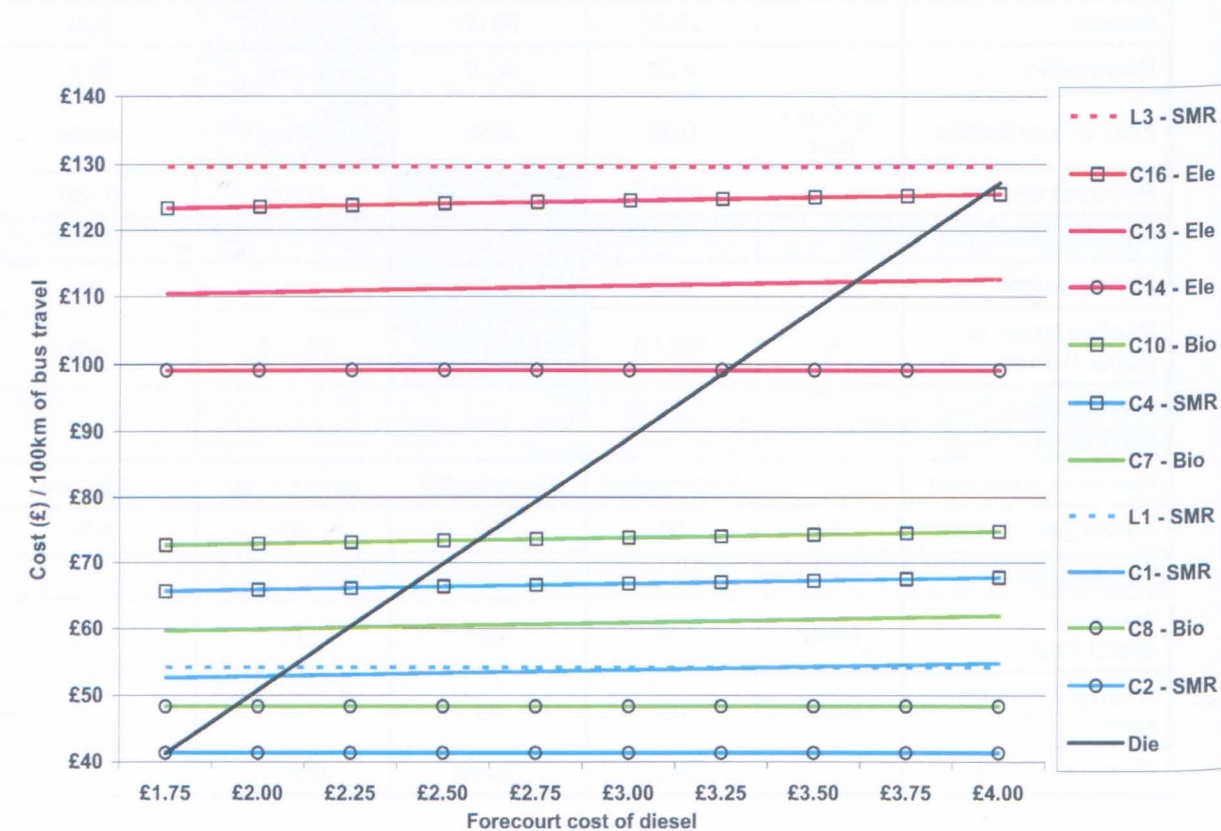


Figure 8-1 Hydrogen cost equivalent points plotted against rising diesel costs.

At this point, it is worth a brief comparison with the costs found in the CUTE project for the pathways modelled here. The CUTE data is taken from Table 5- 3.

<sup>32</sup> The cost equivalent point is a term used to define the cost of hydrogen in terms of the cost of diesel. It is also sometimes referred to as the “break even point”.

	Delivered by truck	Local SMR	Local Electrolysis
<b>This research model results</b>	€2.97 – €7.09	€3.06	€7.32
<b>CUTE results</b>	€5.34 – €21.35	€12.54 – €15.56	€10.15 – 13.98

**Table 8-4 Model results versus CUTE (cost / kg of hydrogen)**

There would appear to be major differences between the actual results from CUTE and this research model. However some of these discrepancies can be easily explained.

The trucked in option in this research model is reasonably close to the CUTE minimum case. Considering that the typical factory gate hydrogen price in 2006 was £1.26 (€1.76) per kg (ONS, 2006) it seems that even the CUTE minimum case is at the high end of the cost range. Otherwise, using the CUTE minimum cost for delivering the hydrogen would be €5.34 - €1.76 = €3.58. This would imply that hydrogen costs twice as much to deliver as to make. The CUTE maximum case is significantly outside the cost range in this research model, there may be other extenuating circumstances here, such as the significant losses due to boil off when supply does not match demand.

The discrepancy between the two SMR results reported in Table 8-4 are more difficult to explain. The CUTE costs are actual and the results in this research modelled, so one could argue that the CUTE costs are more accurate. However, If the CUTE price range is compared with the factory gate price provided by ONS for the localised SMR scenario<sup>33</sup> (€1.76 / kg), the CUTE localised hydrogen production at €12.54 – €15.56 / kg is seven to eight times more expensive than the ONS figure. In the modelled result, costs are reported at €3.06 / kg, it is reduced to a factor of less than two compared with ONS. Whilst it is appropriate to acknowledge that the CUTE results were “real” it may also reflect learning costs from the project which may not actually be appropriate when modelling future systems.

The discrepancy between the Electrolysis results are also difficult to explain, although the model testing in chapter 7 also identified reasonably different results for electrolysis costs varying by as much as 33% (refer to section 7.6.4). Also, there is some uncertainty in model with respect to production costs, approximately +/- 8% according to the sensitivity analysis carried (refer to section 7.6.2). Although this would not explain all of the discrepancy, other factors such as learning costs and additional costs associated with small scale operations may contribute to the differences.

<sup>33</sup> Localised production costs would be similar to the factory gate price of hydrogen from ONS as both include the same number of stages, the main difference would be the economies of scale which can be achieved with large scale centralised production.



### 8.1.2 Pathway emissions

In considering the emissions from each of the pathways, one can see what potential hydrogen has (if any) to reduce emissions of what is the most common greenhouse gas. It should be noted that results in Figure 8-2 only include emissions from production, distribution and use of the fuel, they do not take into account manufacturing of equipment.

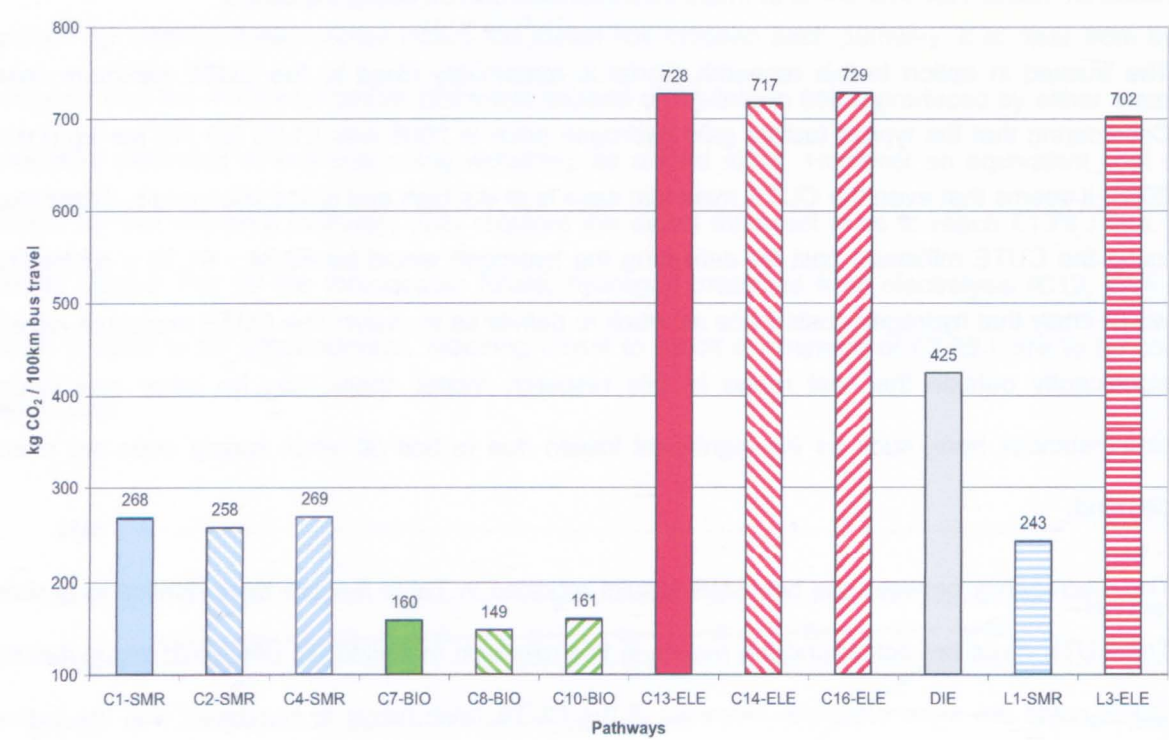


Figure 8-2 Emissions for hydrogen and diesel pathways

The results follow a similar pattern to costs, in that the SMR and biomass pathways produce the least emissions with electrolysis producing the most. These results do not allow for sequestration of carbon produced in either the SMR or biomass pathways. The biomass pathways assume a biomass carbon efficiency of 80%, ie: it assumes that 80% of the carbon produced during the production of hydrogen is consumed during the plant growth phase. This is a reasonable assumption, providing that this has not been included in the earth's overall carbon balance when accounting for greenhouse gases such as carbon dioxide. Otherwise it would not be appropriate to use a biomass efficiency value in this modelling. For the purposes of this modelling it is assumed that the biomass comes from crops planted specifically for biomass production and conversion to hydrogen. Emissions during the SMR process are somewhat fixed due to the chemical reactions required to convert natural gas into hydrogen and can only be reduced with the addition of CCS (carbon capture and storage technology). SMR processes typically produce approximately 38% less CO<sub>2</sub> when compared with diesel on a per distance basis. At first, this appears to be a

significant advantage, except that one could actually burn the CNG direct in an internal combustion engine with similar emissions reduction potential when compared with diesel. One could argue that hydrogen produced by the SMR process alone without CCS, shows no emissions benefit if one compared a hydrogen FCV vehicle at approximately 2.6 kg CO<sub>2</sub> / km (Figure 8-2) with a CNG vehicle at approximately 1.06 kg CO<sub>2</sub> / km (Jayaratne ER et al., 2009).

The Electrolysis pathways are significantly worse than the diesel reference case in terms of emissions. Electricity generation is based on a UK average mix, which is predominantly hydrocarbon based (natural gas and coal) at present. This would also tend to imply that battery powered electric vehicles may not be quite as environmentally friendly as claimed, unless the electricity is produced from lower carbon technologies such as nuclear etc., or CCS technology is used. There is of course a cost increase due to these changes and consequently both costs and emissions, although separate parameters, are interconnected.

As in section 8.1.1, it is appropriate to consider the results in Figure 8-2 with the CUTE results. Before looking at the SMR and Electrolysis differences, it is necessary to assess the diesel reference case to make sure that comparisons are drawn on an even basis. CUTE uses three measures for emissions, Global Warming Potential (GWP), Photochemical Ozone Creation Potential (POCP) and Acidification Potential (AP) (Binder M et al., 2006, p60). However apart from defining GWP gases as Carbon Dioxide (CO<sub>2</sub>), Methane (CH<sub>4</sub>) and oxides of nitrogen (NO<sub>x</sub>), it does not define the gases attributed to POCP and AP. A paper on the STEP project defines POCP as “emissions that increase the production of tropospheric ozone” and AP as “emissions that cause the acidification of rain, soil and water” (Ally J and Pryor T, 2007).

This research model treats the various gases on the basis of “CO<sub>2</sub> equivalent” values which includes CO<sub>2</sub>, Hydrocarbons and NO<sub>x</sub>. For the diesel base reference case, the model reports 4,210 g CO<sub>2</sub>e / km, which is reasonably close to the emissions results of 3,954 CO<sub>2</sub>e / km reported in Table 8-5 below.

	g / km	g CO <sub>2</sub> e / km
Hydrocarbons	0.023	0.5
Carbon Monoxide	0.136	n/a
Nitrogen Oxide	10.4	2960
Particulate matter	0.022	n/a
Carbon Dioxide	994	994

Table 8-5 Typical London bus emissions  
 Data provided by Transport for London (Clark G, 2004)



It is more difficult to draw a direct comparison between the CUTE project results and this research model for the SMR and Electrolysis pathways. CUTE deliverable No.8 compares GWP against a diesel base line reference case but only reports in terms of percentage increase. For the SMR cases this is reported as +140% and +40% for the Citaro and Nebus FCVs respectively. For the Electrolysis case it reports +371% increase (Binder M et al., 2006). Without knowing the actual values used for the diesel baseline reference case it is not possible to draw direct comparisons between the research model, which reported 2,630 and 7,230 CO<sub>2</sub>e / km for the SMR and Electrolysis pathways respectively.

### 8.1.3 The cost of distribution compared to production

The next stage in this modelling section is to consider whether the cost of distribution is a significant proportion of the overall delivered cost of hydrogen when compared with diesel.

Figure 8-3 shows the proportion of production to distribution costs for the chosen centralised pathways. The reference case of diesel reports the cost of diesel distribution as being approximately 5% of the forecourt price. In all cases, hydrogen distribution is a significantly higher percentage of the delivered cost, although they vary considerably.

A robust method of analysing the pathways is to compare against the same production method, ie: compare C1, C2 and C4 against each other and so forth, since the actual production costs for these pathways are equal and it is the distribution costs which vary. The diagram shows that depending on the pathway chosen the distribution costs vary between approximately 33%(C2) & 58% (C4) of the overall cost of hydrogen.

Two conclusions can be drawn from this diagram. Firstly, that hydrogen delivery costs are a significantly higher proportion of the overall cost when compared with diesel and secondly, by choosing the optimum delivery method for any given production method, significant savings of up to 25%, in the case of this particular pathway can be achieved. The most cost effective delivery mechanism for this particular scenario is gaseous hydrogen compressed in a pipeline (C2), which is perhaps not surprising given the boundary conditions of relatively high demand (5,000 kg / day), a long supply chain (200 km) and rural terrain (cheaper installation costs).

Whilst the first conclusion is significant in that it implies that the optimum distribution system can contribute significantly in identifying the cheapest overall hydrogen pathway, it cannot be justified

by analysis of one particular supply chain in terms of demand, length and terrain. This will need further investigation and will be addressed in scenario SC2.

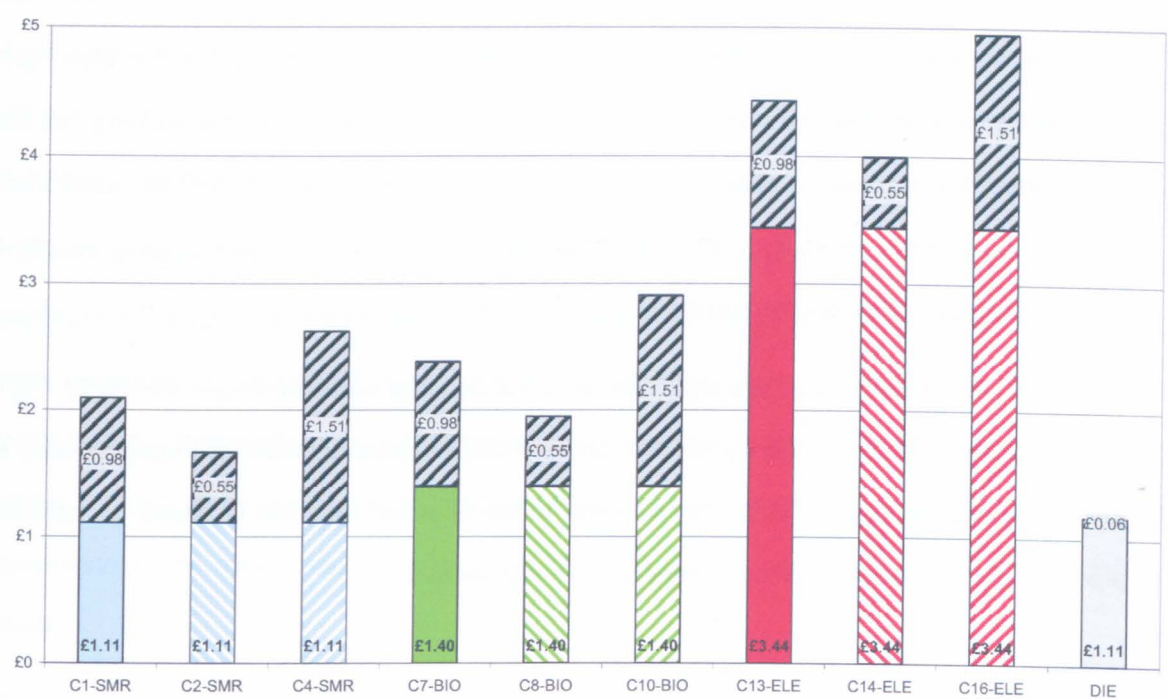


Figure 8-3 Production and distribution costs for a variety of pathways

For colour coding refer to Table 8-1, hatched grey represents the distribution cost of the associated pathway as percentage of overall cost

8.1.4 Hydrogen distribution cost breakdown

There is a significant variation in the overall costs for different hydrogen delivery pathways, and further analysis is needed to identify the individual cost components of each step of these pathways. To analyse the different pathways, the costs need to be itemised by their component stages, using a similar approach to CUTE. Not all stages are common to all distribution methods, for example liquefaction and on site vaporisation are only applicable to delivery by liquid road tanker. Tanker loading compression is only applicable to gaseous hydrogen delivery by road tanker. In the scenario of gaseous hydrogen pipeline delivery, the compression required is included in the transportation element of the cost. This is necessary as compression costs are a function of supply chain length.

The three major cost components in

Figure 8-4 are storage, liquefaction and transportation for gaseous hydrogen delivery by road. As liquefaction is required to transport liquid hydrogen it is included as part of the transportation cost. This simplifies the costs into two categories.



- On site storage which is fixed in the model and based on reported costs by CUTE and other sources (see chapter 7 for details). These figures appear to be counterintuitive. If one considers that gaseous static hydrogen storage costs £0.40 per kg, this is almost as expensive as mobile hydrogen storage ie: a gaseous road tanker at £0.44 per kg. Considering that the latter figure includes for all associated delivery costs (truck, fuel, driver costs etc.) this is something that may need further investigation in chapter 9 on technology developments. It should be noted that it may not significantly affect the choice of pathways, as cost reductions would apply equally to gaseous hydrogen delivery by road tanker and pipeline.
- Transportation costs by road are significant at £0.44 /kg of gaseous hydrogen and £0.72 / kg of liquid hydrogen (including the liquefaction cost). It does appear to show hydrogen delivery by pipeline is significantly cheaper, but it needs to be stressed that this is based on optimum pipeline cost of maximum demand, supply chain and terrain.

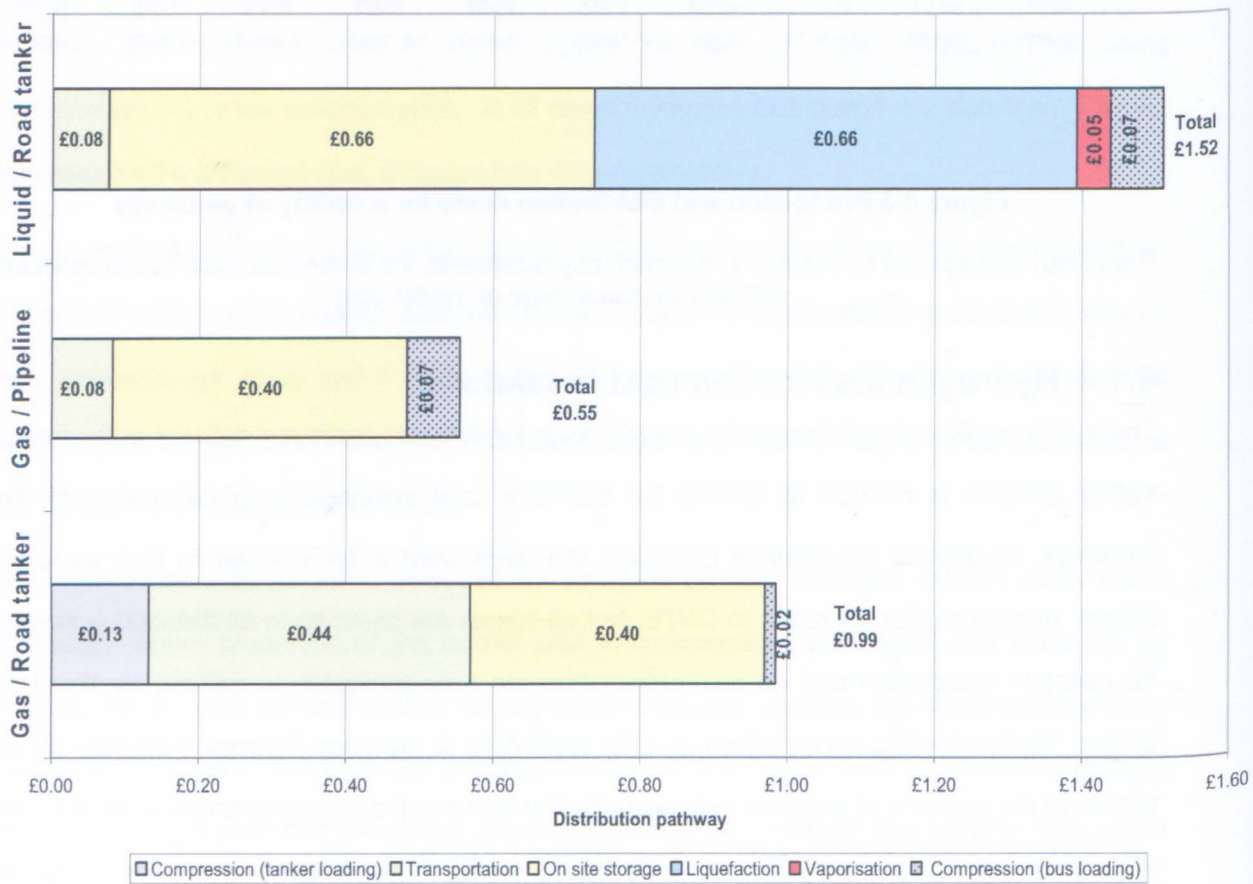


Figure 8-4 Distribution cost breakdown (£ / kg of hydrogen)

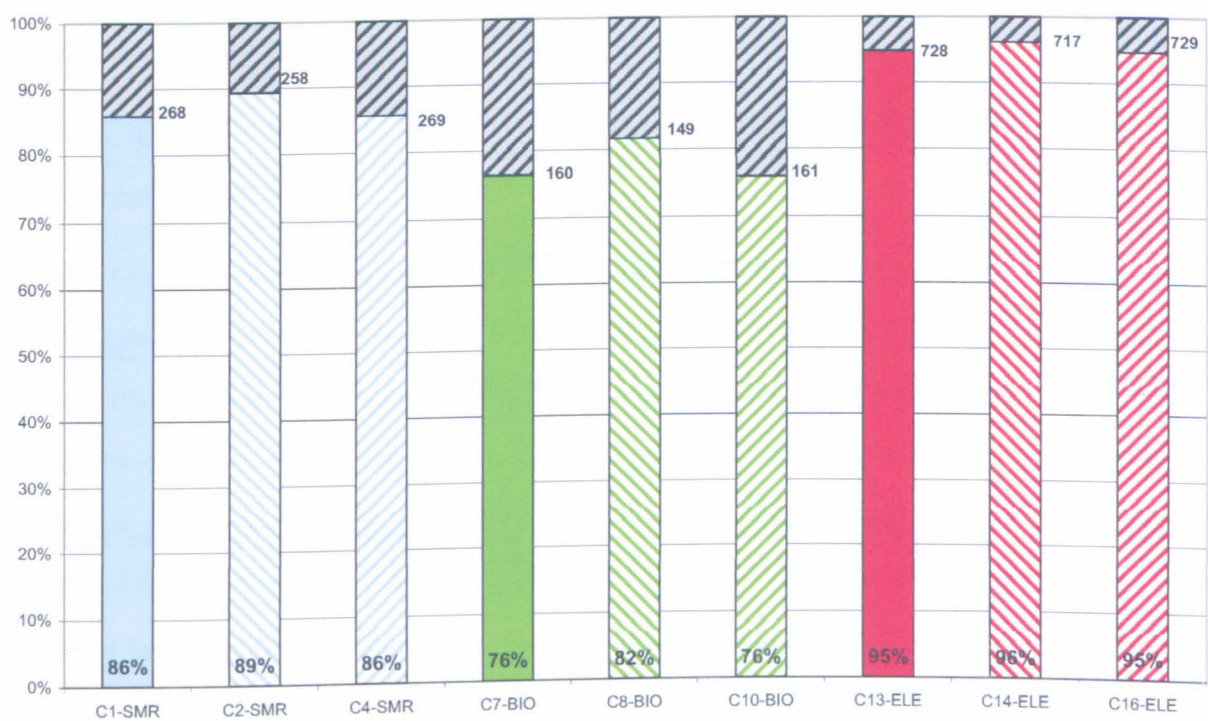
### 8.1.5 Production emissions compared to distribution

To complete the modelling of scenario SC1,

Figure 8-5 shows a breakdown of the production versus distribution emissions of the nine centralised hydrogen pathways. This diagram excludes the reference diesel case emissions for the following reasons explained below.

There are three stages in the supply chain – production, distribution and end use. It is not particularly helpful to measure diesel versus hydrogen by these stages. Hydrogen has effectively zero emissions at the point of use, whereas the majority of diesel emissions are released at the point of use. Conversely, most hydrogen emissions are due to production as shown in Figure 8-5, whilst refining of hydrocarbons to produce diesel is not emission free it is a relatively small proportion of the overall emissions as most of the emissions are due to combustion of the fuel itself.

This leaves the emissions from the hydrogen distribution systems which can reasonably be compared with diesel. For the boundary conditions in this scenario diesel results yield 0.32 kg CO<sub>2</sub> per kg of diesel. The hydrogen pathways vary between 0.6 to 1.35 kg CO<sub>2</sub> per kg of hydrogen. This apparent advantage of the diesel case can easily be explained by the carrying capacity of road tankers for diesel and hydrogen, as more hydrogen trips are required to deliver the same amount of energy as contained in diesel.



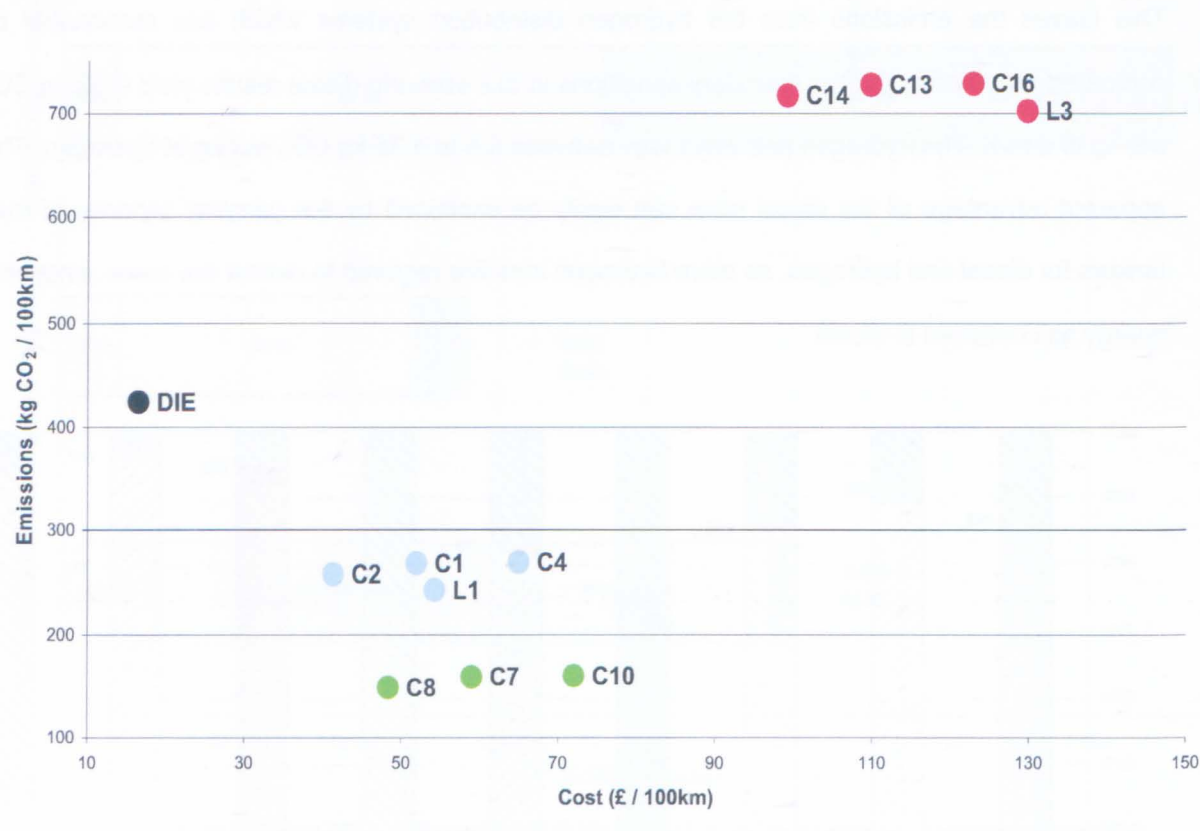
**Figure 8-5 Production and distribution emissions**

Hatched grey represents the proportion of the emissions due to distribution. Figures to the right are the actual emissions as shown in Figure 8-2

Whilst the distribution emissions are proportionally smaller than their associated distribution costs (refer to Figure 8-3), they still represent a reasonable proportion of the overall pathway emissions, and consequently any reduction by selecting optimum pathways would be desirable.

**8.1.6 Summary of Scenario SC 1 results**

Scenario SC1 represents the current situation with respect to both cost and emission of hydrogen pathways versus the diesel reference case. These results are based on a fixed demand and supply chain length, so can only be considered a snapshot of one typical system. The cost and emissions for each pathway in this scenario have been reproduced on the scatter diagram Figure 8-6. The optimum pathway of low cost and low emissions would be located in bottom left hand corner of the diagram.



**Figure 8-6 Pathway costs (£/100km of bus travel) and emissions (kg CO<sub>2</sub> / 100 km bus travel)**

Based on the current typical energy data used in this modelling, it is possible to draw a number of conclusions from the results. Firstly, hydrogen is currently more expensive than diesel to produce.



## **8.2 SC 2 – Variations in demand and supply chain length**

### **8.2.1 Model parameters**

In this scenario, variations in demand and supply chain length of the hydrogen pathways will be investigated further. For convenience, the diesel pathway has been excluded, as it has already been shown to be only a small proportion of distribution costs (refer to Figure 8-3) and due to the capacity of diesel tankers, it is less likely to be price sensitive for reasonable supply chain lengths. In addition, this analysis only applies to the centralised production methods, as localised pathways do not transport hydrogen, have no distribution system and are not sensitive to variations in supply chain length.

To ensure reasonable comparison with scenario 1, the base line data used in Table 8-3 will be applied in this scenario (2), with the following exceptions:-

- Hydrogen demand is varied from 500 to 5,000 kg / day (SC 1 fixed at 5,000 kg/day)
- Supply chain length is varied from 25 to 200 km (SC 1 fixed at 200km)
- Terrain, is varied between 0 / 50 / 100% rural along with relevant road tanker speeds applied (Sc 1 fixed at 100% rural)

A demand range of 500 to 5,000 kg / day would typically represent an equivalent to fuelling a bus fleet comprised of ten to one hundred buses. A supply chain length of 25 to 200 km would represent the minimum and maximum likely supply chain lengths for centralised production within the UK. For distances of less than 25km, localised production would typically be considered, or alternatively, driving the buses to the hydrogen production facility for re-fuelling, if the distance was just a few km (as in the CUTE London trials, where the re-fuelling facility was remote for the bus depot). At this stage, delivery by diesel powered truck is considered for the tanker pathways. In other words, hydrogen powered fuel tankers (FCV trucks) are not considered.

With three pathways considered, and effectively three variables explored stepwise, a significant number of data points can be expected, so it is important to ensure reasonable sensitivity with respect to intervals between data points in the data sets. The following limits and intervals were selected:-

- Demand – 500 to 5000 kg/day at 500kg intervals. This effectively represents a bus depot from 10 to 100 buses with intervals of 10 buses.
- Supply chain – 25 to 200 km at 50km intervals (initial interval 25 km). 25km is the minimum below which localised production may be considered or driving buses to the re-fuelling as mentioned previously. 200 km is considered the maximum likely distance between a hydrogen production facility and bus depot within the UK.
- Terrain – 0% / 50% / 100% variation between rural and urban. 0% rural would represent a city or town system, 100% rural would represent a country system such as the CDCT demonstration project referred to in chapter 5.

The data results are shown in Appendix 5, the cost data results from SC1 Figure 8-4 are represented in the bottom right hand corner (5000kg/day, 200 km supply chain and 100% rural terrain). As there is no comparison between the hydrogen and diesel pathways, it is not necessary to report results in terms of bus travel as per SC1. Results quoted here based on £ / kg H<sub>2</sub> for costs and kg CO<sub>2</sub> / kg H<sub>2</sub> for emissions.

### **8.2.2 Preliminary observations**

In all scenarios, gaseous pipeline is the cheapest pathway option, which may seem initially counter-intuitive given the relatively high installation costs associated with pipeline installations and contradicts some results reported elsewhere. However nearly all natural gas in the UK is delivered by pipeline except for remote areas of the UK with low demand. In comparison, the hydrogen results in this research report a similar situation, the cost differential increases with increasing pipeline distance. It is likely that for very small demand of 50kg / day (one bus) gaseous hydrogen delivery by road tanker would be the optimum pathway, but this sort of demand is not considered likely for a “bus fleet” and hence falls outside the scope of this research.

In terms of emissions, the difference is much less clear when compared with road tanker deliveries. It should be noted that most emissions for pipeline pathways come from electricity required for compression and in this case electricity is based on UK average fuel feed mix. It would therefore be

possible to reduce the emissions levels but at some cost if renewable electricity were used for compression.

The cost of gaseous hydrogen delivery by road is almost independent of demand once a level of approximately 1000 kg / day is required. Below that level there is a slight cost variation. As expected, cost increases with supply chain length, almost independently of demand once a certain level is achieved. Liquid hydrogen appears to be independent of demand according to the results but dependent on supply chain length due to increased costs of liquefaction and storage.

Road tanker emissions results are perhaps not quite as easy to decipher. Given the difference in tanker sizes (typically 360kg for gaseous hydrogen and 3600kg for liquid hydrogen) one might expect liquid hydrogen pathways to have a consistent advantage for all demands and supply chain lengths. However two other factors need to be considered, eg: liquefaction (for the liquid pathway) and compression (for the gaseous pathway), both of which are very energy intensive. Another slightly unusual result is the research model reports consistent emissions values, regardless of demand and supply chain length. This is a slight anomaly, due to size of pipelines used in the model, which have excess capacity compared to all demand scenarios. This results in a relatively low pressure drop in the pipeline and hence a small amount of additional power required compared to the power required to load the tanker to 250 bar g.

8.2.3 Cost results

Full cost results are reported in Appendix 5 for all variables defined in section 8.2.1, ie: for demand, supply chain length and type of terrain. The following table is an abbreviated summary of Appendix 5, showing the results for the minimum and maximum demand.

Cost of hydrogen delivery (pence per kg)									
Delivery distance (km)	Gaseous road tanker			Liquid road tanker			gaseous pipeline		
	Urban Terrain								
	100%	50%	0%	100%	50%	0%	100%	50%	0%
	Demand = 500 kg / day								
25	77.2	75.7	74.9	146.4	146.1	146.0	57.6	57.4	57.2
50	83.0	80.1	78.4	147.4	147.0	146.7	58.4	58.0	57.7
100	94.7	88.9	85.5	149.5	148.7	148.2	60.1	59.3	58.6
150	106.3	97.7	92.6	151.7	150.4	149.6	61.7	60.7	59.6
200	118.0	106.4	99.6	153.8	152.0	151.0	63.4	62.0	60.5
	Demand = 5,000 kg / day								
25	76.0	74.5	73.7	146.4	146.1	146.0	55.1	55.1	55.1
50	81.8	78.9	77.2	147.4	147.0	146.7	55.2	55.2	55.1
100	93.5	87.7	84.3	149.5	148.7	148.2	55.4	55.3	55.3
150	105.1	96.5	91.4	151.7	150.4	149.6	55.6	55.4	55.3
200	116.8	105.2	98.4	153.8	152.0	151.0	55.7	55.6	55.4



**Table 8-6 summary of Appendix 5 results**

In terms of absolute costs, it would appear that for all boundary conditions modelled here, gaseous delivery by pipeline is the cheapest method of delivery, with gaseous hydrogen delivery by road as the second cheapest option and liquid hydrogen by road costing significantly more. Before investigating absolute costs further it is worth looking at the variations in costs for each method based on demand and supply chain to see how sensitive they are to variation. Observations can be summarised as follows:-

- Demand has little effect on gaseous hydrogen delivery by road as a function of demand, but supply chain length has a more significant effect with a difference of 40p at minimum demand.
- Demand seems to have no effect at all on liquid hydrogen delivery costs by road, and supply chain length is marginally affected, with a variation of about 8p / kg at minimum.
- Demand has about 5p / kg effect on gaseous hydrogen delivery by pipeline for short supply chain lengths but this increases to 8p / kg at the maximum supply chain length of 200km.

Some of the choices of demand and supply chain length in Table 8-6 can be considered unrealistic (eg: 100% urban terrain for a supply chain length of 200km), but in general, the results should reflect typical hydrogen delivery requirements within the UK. Although it would appear that road tanker delivery is significantly more expensive, particularly liquid hydrogen, there are perhaps situations where pipelines may be impractical for reasons such as access to land etc., high historic costs or some other overriding factor.

At this stage, it appears that liquid hydrogen delivery by road can be excluded on the basis of cost as it can add almost £1/kg to overall hydrogen costs. Although significantly more hydrogen can be transported in each tanker, it would seem that any advantage is cancelled out by the additional cost of liquefaction. Considering that fleet vehicles tend to store hydrogen on board in gaseous state, there seems little reason to consider liquid hydrogen further on the basis of significantly higher costs.

The inaccuracy of generic pipeline models may affect results slightly. It has been calculated in the model that the worst case errors in pipeline capital cost estimates might add perhaps a few pence per kg of hydrogen. It would appear therefore that if considering solely costs, pipeline distribution should be the preferred option based on initial evaluation of costs, with cost preference to higher demand scenarios as higher throughput results in lower costs due to efficiency gains.

### 8.2.4 Emissions results

Emissions results are summarised here:-

- Gaseous tanker emissions range between 1.16 and 1.52 kg CO<sub>2</sub> per kg H<sub>2</sub>.
- Liquid tanker emissions range between 1.21 and 1.56 kg CO<sub>2</sub> per kg H<sub>2</sub>.
- Pipeline emissions are constant at 1.07 kg CO<sub>2</sub> per kg H<sub>2</sub>.

One would intuitively expect pipeline emissions to increase with distance, which is correct due to pressure drop, but as the model contains a single algorithm for pipeline pressures it does not take into account delivery pressure as it is again boosted during loading of the vehicles (hence a single value rather than a range). It can, however be considered indicative. It would appear from these results that there is no single preferred method of delivery when considering delivery emissions only.

### 8.2.5 Cost comparisons (this research model v Yang and Ogden)

In Chapter 4 , a paper titled “Determining the lowest cost hydrogen delivery mode” was reviewed. It is used here for comparison purposes with these results. Although not a direct comparison (as it is based on US data), it is not clear whether the paper takes into account different terrains for pipeline costs. This section focuses only in the cost discrepancies; it is more difficult to analyse the emissions unless data, such as energy mixes for electricity generation are reported.

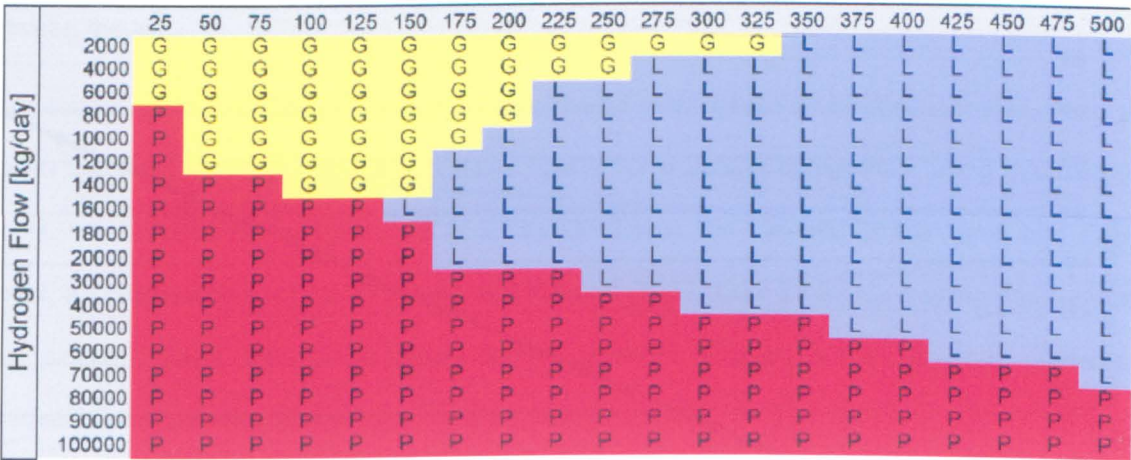


Figure 8-7 Distribution costs comparison (Yang C and Ogden J, 2006a)

Mode map describing the lowest cost hydrogen delivery options as a function of hydrogen flow and transport distance. Distance quoted is km. G = compressed gas delivery by trucks, L = liquid gas delivery by trucks and P = compressed gas by pipeline (nb: hydrogen flow is not linear)

Figure 8-7 shows the most cost effective delivery method based on hydrogen demand and supply chain length. It considers a much wider range (100,000kg/day and 500km) than this research model (5,000 kg / day and 200km). This diagram is similar to Figure 4-3 by except that the values are represented numerically rather than curves in the diagram by Joffe and Strachan and has been used for comparison as it is easier to map the results of Table 8-6 on to this diagram. The areas of interest in the results from Yang and Ogden are the top left hand corner of Figure 8-7, where it would seem that for the boundary conditions in scenario 2, delivery by gaseous hydrogen tanker is the least cost option.

Interestingly, according to Yang and Ogden, as supply chain length increases liquid hydrogen delivery by road is the preferred delivery method, yet as demand increases, gaseous pipelines are the preferred delivery method. This research model also concludes that as supply chain length increases, the cost differential between gaseous and liquid hydrogen delivery by truck reduces, this is shown in Figure 8-8, as the supply chain length is extended. In this specific case, it shows that the break even point would be about 325 km (outside the boundary of this research). Although not an exact match with the Yang and Ogden model, it does show some consistency when compared with Figure 8-7. However, a supply chain length of >325km is an unlikely scenario in the UK for reasons given earlier. This tends to support the argument that for the UK at least, liquid hydrogen delivery by truck is not economically viable.

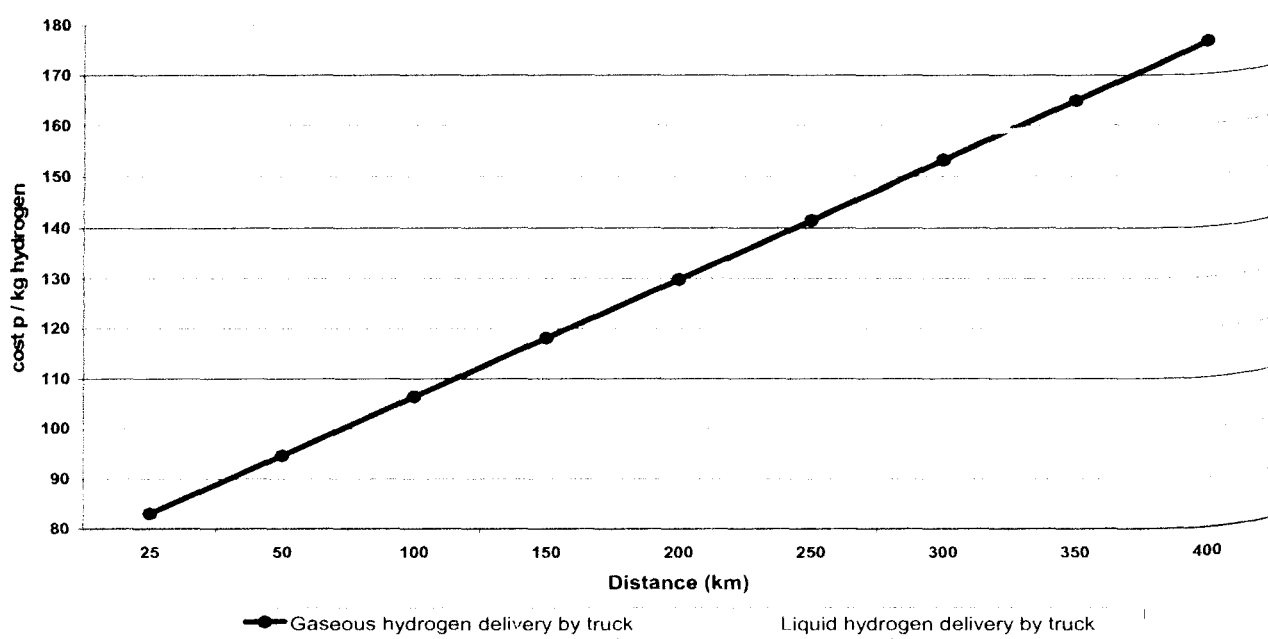


Figure 8-8 Delivery cost projections

Gaseous hydrogen = 360kg tankers, Liquid hydrogen = 3,600kg tankers,  
For a constant flow of 500 kg/day

### 8.2.5.1 Comparison of pipeline cost

Pipeline estimating costs vary significantly, and are worthy of further investigation. In their paper,

Yang and Ogden use the following data for pipelines:-

Installation and ROW cost - rural	\$300,000 / km
Installation and ROW cost - urban	\$600,000 / km
Pipeline capital costs (\$/km) ( $d_{\text{pipe}}$ is pipeline diameter in inches)	$\$1869 (d_{\text{pipe}})^2$
Maximum pipeline inlet pressure	70 atm (1029 psi)
Pipeline output pressure	35 atm (515 psi)
$CF_{H_2 \text{ production}}$ (CF= Capacity factor)	90%
$CRF_{\text{pipeline}}$ (CRF = Capital Recovery Factor)	15%
$CRF_{\text{compressor}}$ (CRF = Capital Recovery Factor)	15%
Fixed operating costs	5% of total capital
Compressor capital costs $S_x$ is compressor size in kW	$\$15,000 (S_x / 10\text{kW})^{0.9}$
Compression energy requirements	0.7 – 1.0 kWh / kg

**Table 8-7 Pipeline installation data**

(Yang C and Ogden J, 2006a, table 7)

The compression energy requirements for this research model typically calculates 1.1 kWh / kg of hydrogen whereas Yang and Ogden use 0.7 – 1.0 kWh / kg as shown in Table 8-9. This is obviously dependent on compressor ratios and efficiencies, but shows reasonable consistency between the two.

Compressor costs: this research model selects capital costs based on compressor size, Yang and Ogden use the formula in Table 8-9. Typical figures for a 235kW compressor using this research model, would result in a capital cost of £120,000. Using the formula for the Yang and Ogden model, a compressor cost would equate to £135,000 ( $\$257,000 / \$1.9 / \text{£}$ ), making the two costs very similar. These differences would favour pipelines slightly in the research model and disadvantage pipelines slightly in the Yang and Ogden model.

Pipeline costs: This research model assumes small pipeline costs are similar and linear for both urban and rural terrains (refer to appendix 4 section 1.3.4.3 for further explanation). For a maximum demand and supply chain this would equate to capital costs of £403,000 for urban and £270,000 for rural terrain on a per km basis. The Yang and Ogden model uses costs as shown in



Figure 8-9 below. Although not linear, for all conditions, within the pipe diameter range of 3" to 6"<sup>34</sup> the curves in Figure 8-9 can be considered to be approximately linear within the range of 3" to 6". For pipelines >6" the slope of the curve is such that it cannot be considered linear.

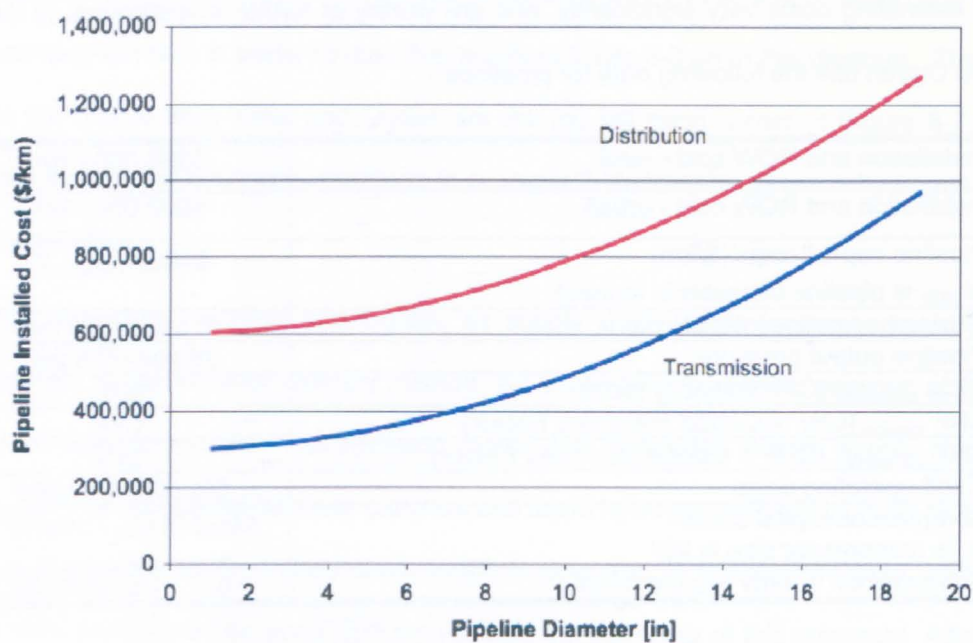


Fig. 1. Pipeline model installed cost (\$/mile) dependence on pipeline diameter.

**Figure 8-9 Pipeline installation costs**  
(Yang C and Ogden J, 2006a)

Based on a 6" pipeline in Figure 8-9, Yang and Ogden reports \$380,000 for transmission pipeline and \$640,000 for distribution pipelines, based on a per mile basis. This would equate to £320,000 (transmission) and £539,000 (distribution) on a per km basis. With this research model reporting of £403,000 (urban) and £270,000 (rural) on a per km basis, there is clearly some discrepancy. Yang and Ogden appear to use a typical natural gas model whereby gas is transmitted at high pressure in transmission lines and let down into lower pressure distribution lines for final use. This is not really appropriate for hydrogen, where end delivery is required at the highest possible pressure. In effect, Yang and Ogden figures are based on "pressure" and this research model figures are based "on terrain". If we then consider just the transmission figure for Yang and Ogden (320,000 / km) this is almost exactly the mid point between the research model figures of £403,000 km and £270,000.

It is reasonable to conclude that whilst the capital costs are similar in both models, there are likely to be discrepancies in results due to the way these capital costs are used in each model. This appears to be borne out in the difference between this research model results and Figure 8-7.

<sup>34</sup> The research model uses pipes in the range of 3" to 5" for all pipeline calculations.

8.2.5.2 Comparison of road costs

Tanker delivery comparison is more difficult between the two models due to methods used. For example, Yang and Ogden assume gaseous tankers are merely dropped off and left on site as storage vessels, whereas this research model assumes transfer to static on site storage tanks. For further explanation, on this refer to Appendix 4 section 1.3.4.1. One method of comparison is to tabulate the differences between the reported inputs into both models as shown in Table 8-8 below.

	This research model	Yang and Ogden
Truck cab cost	£58,500 (\$111,150)	\$90,000
Truck tanker cost (liquid)	£266,000 (\$505,400)	\$710,000
Truck tanker cost ((gas)	£103,000 (\$195,700)	\$210,000
Average speed	varied	50 km /hr
Fuel consumption	0.368kg D / km (5.8 mpg)	6 mpg
Fuel costs	£1 per litre (\$8.62 / gallon)	\$2 / gallon
Driver wages	£30,000 p.a (\$30.91 / hr)	\$28.75 /hr
OPEX costs	5% per annum	5% per annum
CAB CAPEX life	25 years	5 years
Tanker CAPEX life	25 years	20 years

Table 8-8 Comparison of tanker model input data

Although much of the input data is similar, there is a significant different in fuel costs for the delivery trucks. This research model was revised to reflect realistic truck delivery speed and is in fact variable by terrain, so one can assume speeds are similar. Another important factor is truck utilisation. The Yang and Ogden model assumes 24 hour utilisation and only 1 hour “drop off time. The research model uses 16 hour utilisation and allows approximately 3 hours per delivery, for loading and unloading. It is likely that all these factors combine to explain much of the difference between the results.

This was checked by using the Yang data for utilisation, fuel cost and average speed for the minimum demand (500 kg / day) with the shortest supply chain (25km) in this research model. The revised results showed a cost of £16.50 (formerly £22.15) per 100 km of bus travel for delivery by gaseous road tanker compared with £16.58 for delivery by gaseous pipeline. This result implies that gaseous hydrogen delivery by road tanker is the optimum solution which is consistent with the Yang and Ogden results in Figure 8-7. Whilst it is not possible to claim complete consistency between the two models, it is possible to replicate the results of Yang and Ogden in this research model providing similar data is used. It highlights the need to model the supply chain as accurately as possible in this type of modelling.



### 8.2.6 Comparison of emissions

The comparison so far has focused on cost of the two models, as this is where the greater discrepancy occurs. It was reported earlier that it is more difficult to analyse emissions without close scrutiny on energy mixes for electricity generation. The diagram below (Figure 8-10) from the paper by Yang and Ogden reports emissions from pipelines being consistently lower for all distances, and the “break even” cost observed for gaseous tanker and liquid tankers at approximately 200 km and 2,800 kg / day. This research model does not appear to concur with these results (refer to section 8.2.4). Without closer analysis of electricity mix, energy usage and even delivery truck fuel type, further review is very difficult and perhaps meaningless.

Comparison of the pipeline emissions again show a significant difference in the base values with Yang and Ogden in the region of 0.2 kg CO<sub>2</sub> / kg H<sub>2</sub> and this research model reporting 1.07 kg CO<sub>2</sub> / kg H<sub>2</sub>, yet interestingly, both seem to be fairly consistent, regardless of supply chain length. This tends to suggest that different mixes for electricity generation were used in the two models.

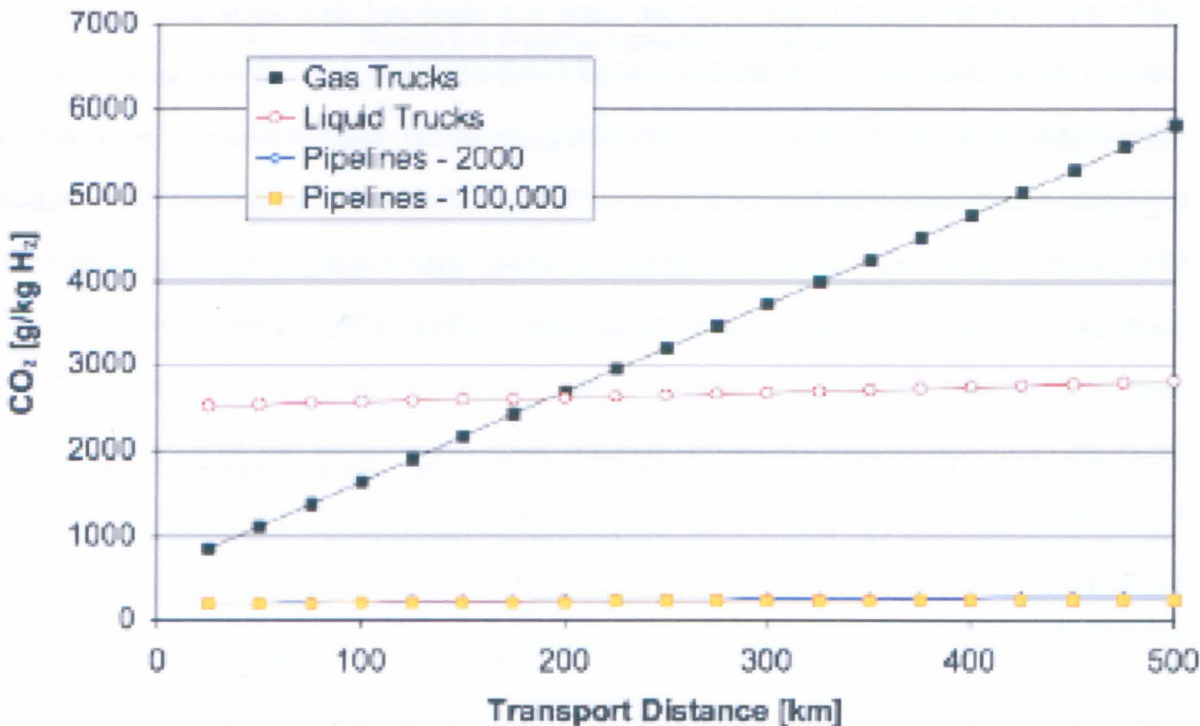


Figure 8-10 Delivery path emissions  
(Yang C and Ogden J, 2006a)

Although not clear from the diagram, pipelines for 2,000 have been obscured by the 100,000 pipeline data. This is reasonable to expect as emissions are reported on the basis of per kg, and hence logically would report almost identical results

### 8.2.7 Conclusion from Scenario SC2 results

The initial results which showed pipelines to be the optimum delivery method for all the boundary conditions, to some extent negated the principal hypothesis about delivery pathways being an important factor in any future hydrogen infrastructure. The subsequent comparison with the Yang and Ogden results highlighted the need for accurate input data and the possible hazards of simulating generic pathways.

The problem with generic pathways is that it is not possible to consider the cheapest method of using hydrogen via centralised or localised production without including delivery costs and emissions. Perhaps the solution is to accept minor inaccuracies of generic modelling of the delivery system when evaluating overall costs. In other words, one should evaluate whether centralised or localised production is the optimum solution for typical vehicle fleets given a defined demand and supply chain. Then once this has been evaluated, one can refine the delivery model for specific applications, or locations.

One final point to note is the impact on costs of the energy required to transport the hydrogen. This highlights the need to consider pathways for a wide variation of energy costs and mixes.

## 8.3 SC 3 – Energy data variations

Before considering variations in energy data, it is helpful to understand how the various forms of energy impact on hydrogen with respect to this research model. Figure 8-12 shows the main energy sources to produce hydrogen and electricity considered in this model. It does not show utility requirements. . The model is designed to correctly calculate the impact of price variations (both feedstock and utility) on each of the pathways. It is therefore possible to vary energy costs between almost any boundaries. The model will calculate the interaction effects on the model (eg: natural gas on electricity)., but it does not take into account the possible interaction effect on oil and gas prices, which is shown dotted to indicate interdependence between the two in Figure 8-12.

There is much debate about the interaction between the market costs for oil and gas. Firstly, as a commodity, they are affected by the fact that the products are often found together in combined oil and gas reservoirs. Secondly, they are also traded as commodities in financial markets which impacts on the costs. Thirdly, price is also affected by supply and demand, which to some extent could also be argued that there is interdependence as they are both used as fuels for heating,

transport and electricity generation. Figure 8-11 below, shows the historical link between oil and gas prices.

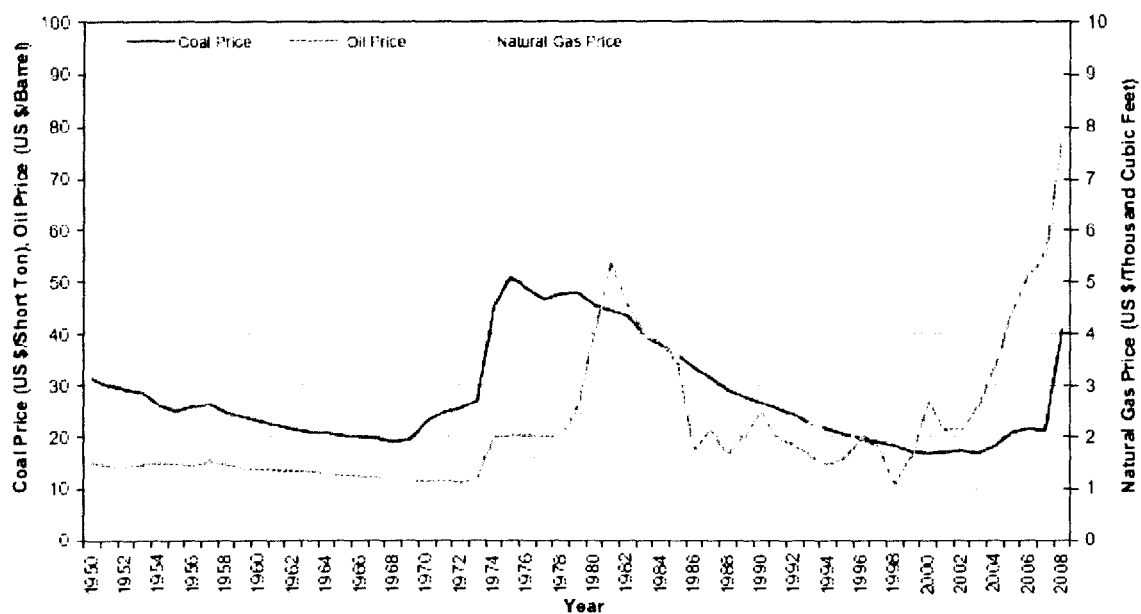


Figure 8-11 – Interdependence between oil and gas prices  
(Shafiee S and Topal E, 2010)

Further consideration of these factors, are considered outside the scope of this research. It does however present a problem when setting the boundaries in this scenario. For example it may not be appropriate to consider oil at the equivalent of \$200 per barrel and leave natural gas at a low level of say £0.015 per kWhr, as one might expect fuel feedstock prices to rise concurrently. Since the model does not consider the interdependence between oil and gas prices, care needs to be taken when inputting these values.

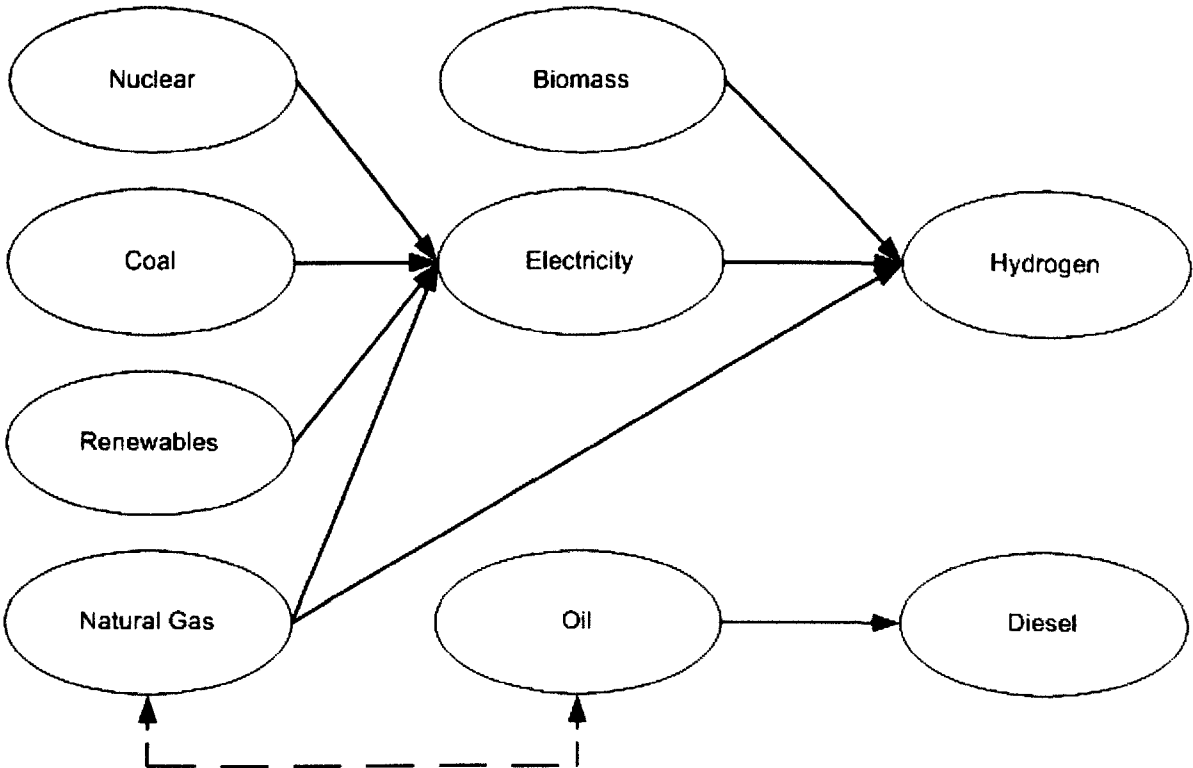


Figure 8-12 - Energy interactions and pathways used in the research model(Dotted line represents the link between oil and gas prices)



Feedstock	Min.	Norm	Max.	Explanatory notes
Diesel	£1.00 / litre	-	£4.00 / litre	Diesel is used as the base reference case for comparison and price range is selected to be consistent with the range used in SC1 to enable potential break even points to be identified
Biomass	£ 0.04 / kg	-	£ 0.08 / kg	Range is based on Royal Commission report (RCEP, 2004, p49)
Natural gas	£0.008 / kWhr	£0.016 / kWhr	£0.032 / kWhr	Natural gas has been shown to have relatively high price volatility. Consequently, the modelling work needs to consider a wide range of price fluctuations. Range has been selected, based on + 100% and - 50% of typical
Nuclear (Electricity)	£0.019 / kWhr	£0.024 / kWhr	£0.024 / kWhr	The minimum value assumes that there is scope for cost reductions due to technology improvements (approx -20%). The maximum value is based on typical current values and that nuclear energy costs increases are subject only to normal inflationary costs. It excludes potential escalation of de-commissioning costs
Coal (Electricity)	£0.030 / kWhr	£0.030 / kWhr	£0.036 / kWhr	The minimum value assumes that coal mining technology is mature and hence little scope for cost reductions. The max value assumes that coal resources (although plentiful) will over time, require more complex technology for extraction and hence an assumed increase of approx. 20%
Renewable (Electricity)	£0.025 / kWhr	£0.049 / kWhr	£0.049 / kWhr	The minimum value assumes that renewable energy has significant potential for cost reduction due to technology improvements (approx. 50%). The maximum value is based on typical current values and that renewable energy costs increases are subject only to normal inflationary costs.
Natural gas (Electricity)	£0.015 / kWhr	£0.023 / kWhr	£0.039 / kWhr	Natural gas prices for electricity generation have been linked to natural gas costs for reforming and hence have a similar range based on the following formula:- Feedstock cost = 70%, Generating cost = 30%

**Table 8-9 - Cost variations for a range of energy vectors**

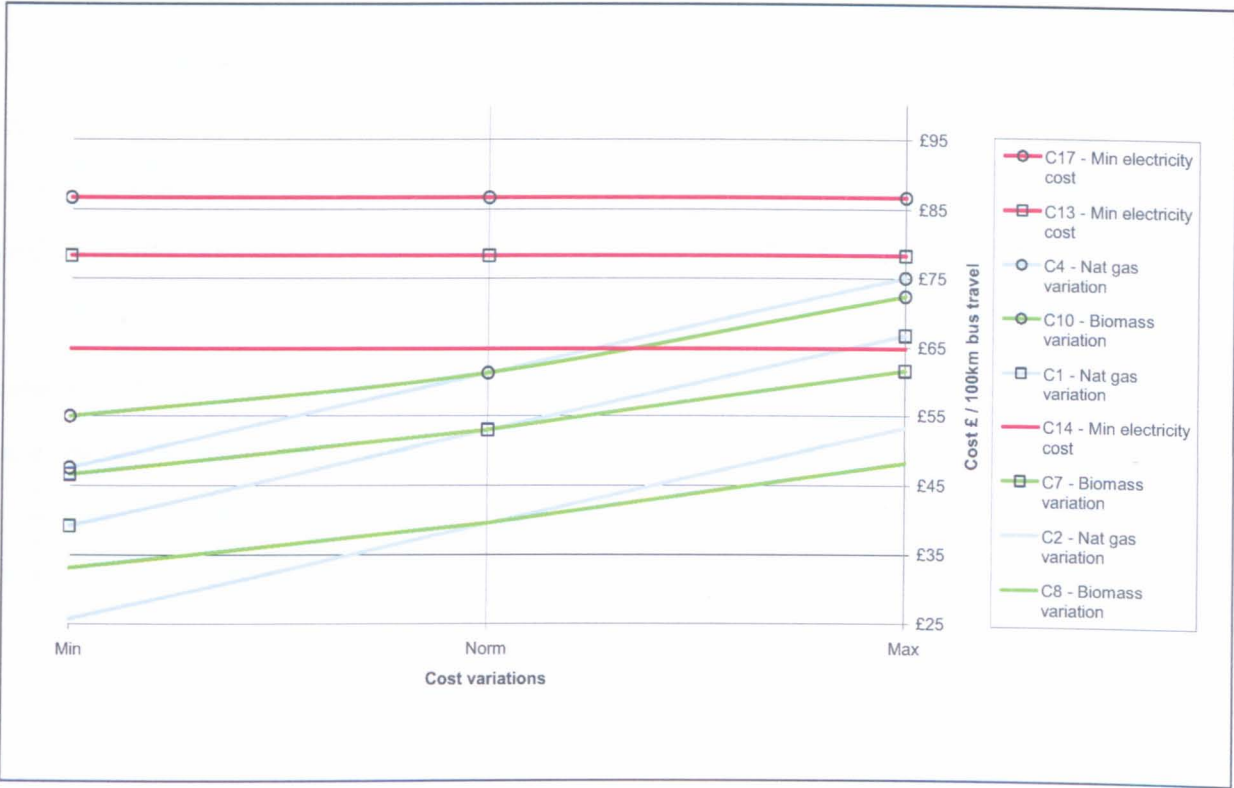
### 8.3.1 Natural gas versus Biomass versus Electricity

It has been shown previously that, at present electrolysis and hence using electricity is not the most cost effective hydrogen pathway in the UK, under the model assumptions. It therefore follows that if electrolysis is to become cost effective, electricity has to become cheaper, or the alternatives such as natural gas and biomass have to become more expensive.

This simplifies the comparison between the three energy sources considered here. In Figure 8-13, costs are plotted for the minimum to maximum values for natural gas and biomass and the



minimum figure only for electricity (based on the energy variations in Table 8-9). Only centralised pathways are shown to enable a direct comparison to be drawn between the different pathways.



**Figure 8-13 - Cost comparison (Biomass and Natural gas)**  
Electricity fixed cost, refer to Table 8-9 (1.9 p/ kWhr)  
Biomass cost range (4 to 8 p/ kg), Natural gas cost range 0.8 to 3.2 p / kWhr

In Figure 8-13 it was assumed that the minimum cost for electricity generation was 1.9 p / kWhr (based on nuclear, minimum value). This was in effect the lowest cost that electricity generation could be achieved, whilst being independent of natural gas prices. The results show that even at the maximum values for biomass and natural gas, electricity is only just cost competitive. The second conclusion that can be drawn from the diagram is that the “break even” point for comparison between natural gas and biomass is quite consistent, varying somewhere between 50 and 55% of the range. As the mid-point is based on typical current energy costs (refer to Table 8-9), it implies that there is little to choose between the two methods of hydrogen production at present.

To put this result into context it would appear that for energy costs lower than 6 p/kg for biomass and 2p / kWhr for natural gas, the cheapest energy source is natural gas regardless of the three different distribution methods. Conversely, for energy costs above 6 p/kg for biomass, and 2 p / kWhr for natural gas, the cheapest source is biomass regardless of the three different distribution methods. For any values in between, the costs are pathway dependent.

These results are for a given set of conditions (5,000 kg/day and 160km - refer to Table 8-3), ie: a fixed demand and supply chain length. However neither, biomass or natural gas will be significantly affected by altering these variables. Electricity is used for compression, diesel is used for delivery trucks, and even if hydrogen were used as the delivery fuel this would have an equal impact on both biomass and natural gas pathways. It therefore seems reasonable to assume that the results shown here can be applied, independently of supply chain length and demand. The only area requiring more detailed analysis is likely to be the intermediate range where no clear advantage is shown.

In this review of energy costs, analysis of electricity cost has shown to have little effect. It would appear that for the ranges chosen, electricity cannot be considered cost competitive as the values used are below current market costs. To assess the cost competitiveness of electricity we have to either increase the costs of biomass and natural gas, or reduce generating costs outside the minimum values assumed so far.

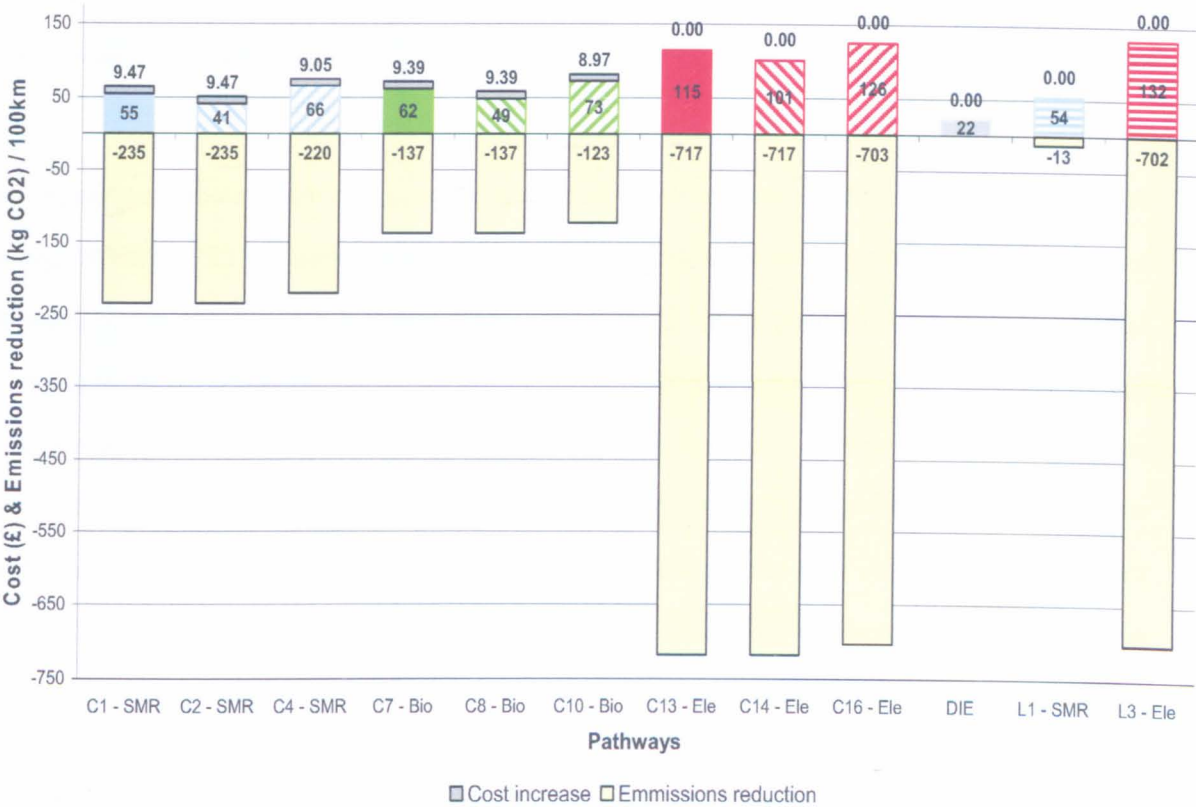
To conclude the section, one must consider the cost of generation of bulk electricity required to make electrolysis competitive. Results from the model indicate that it would require a generating cost in the region of 0.2 p / kWhr even at the maximum values of biomass and natural gas. This is a tenfold reduction in typical current generating costs, which is clearly unlikely to be achieved. This result might at first seem counterintuitive, given the significant reduction in generating cost, but generation cost is only a proportion of the overall cost of electricity. To put the result into perspective, a tenfold cost reduction in generation only produces a 50% cost reduction in the model for delivered electricity assuming all other factors such as cost of transmission, profit etc. remain unchanged.

## **8.4 SC 4 – Emissions reduction potential**

It has been shown earlier that cost and emissions are linked, and hence it may seem inappropriate to analyse cost (SC3) and emissions (SC4) separately. Joint analysis of cost and emissions can make analysis of results complex, due to the number of variables involved. This scenario will investigate the potential for emissions reductions but will report the associated cost increases.

Figure 8-14 shows the base cost of each pathway using the same cost values used in Figure 8-2, but with the additional costs for carbon capture and storage, which is reported as the cost increase. The only other change is the use of 100% Nuclear energy for electricity variation, using a typical electricity generation cost of £0.024 / kWhr. In Figure 8-14, three sets of results are reported:-

- The base cost of the pathway (represented by the coloured bars)
- The actual cost of the emissions reduction technique, where appropriate (represented by the grey bars)
- The amount of associated emissions reduction (represented by the yellow bars below the line).



**Figure 8-14 - Cost and Emissions of pathways based on typical energy costs**  
 Natural gas (£0.016/kWhr), Electricity generation (£0.024/kWhr), Biomass (£0.08/kg), Diesel (£1.20/l)

	C1 - SMR	C2 - SMR	C4 - SMR	C7 – Bio	C8 – Bio	C10 - Bio	C13 - Ele	C14 - Ele	C16 - Ele	DIE	L1 - SMR	L3 - Ele
Figure 8-2	266	258	267	158	149	159	726	717	727	422	243	702
Figure 8-14	31	23	47	20	12	36	8	0	24	422	230	0
Balance	-235	-235	-220	-137	-137	-123	-717	-717	-703	0	-13	-702

**Table 8-10 Comparison of emissions**  
 (kg CO<sub>2</sub> / 100 km of bus travel)

In Figure 8-14 and Table 8-10, the emissions reduction potentials of all selected pathways are shown. The centralised SMR pathways (C1, C2 and C4) and Biomass pathways (C7, C8 and C10), benefit mainly from carbon capture and storage which adds about £9 /100km of bus travel to the overall cost. The Electrolysis pathways (C13, C14, C16 and L3) all benefit from the use of nuclear energy. However it should be noted these pathways are amongst the most expensive initially.

It is clear that hydrogen has significant potential to reduce emissions if CCS technology is applied. Even the worst scenario hydrogen pathways can reduce emissions of carbon dioxide by two thirds,

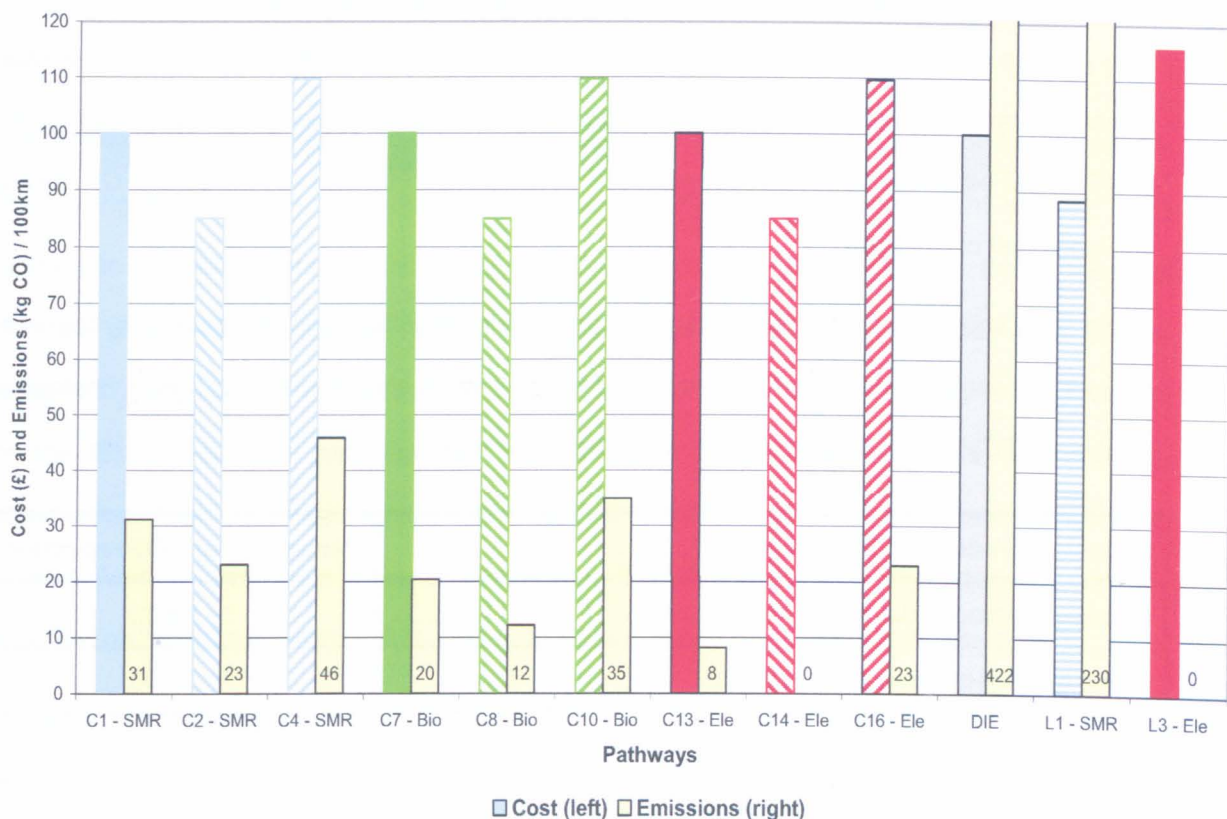


with the exception of L1-SMR (localised hydrogen production by SMR). This pathway has limited potential without including carbon capture and storage. As it is localised it would require additional processing facilities and the captured carbon dioxide to be transported back to a centralised facility either by tanker or pipeline. This would increase the distribution requirements. Considering that it is not even the cheapest pathway, it seems unlikely to be a viable pathway if emissions are an important factor.

Although there may be significant emissions reduction potential with the hydrogen pathways, there are wide variations in costs, none of which are competitive with diesel. At £22 / 100km, diesel is half the cost of the cheapest hydrogen pathway, with some being five times more expensive. Perhaps a more useful way to draw a comparison between cost and emissions is to “equalise” the pathways by adjusting the raw energy costs accordingly. This would enable analysis of the emissions of each pathway with equal costs, it would then show which pathways have the potential for the lowest emission, with costs equalised. It is difficult to achieve, due to interactions between energy prices in the model and pathway costs but in Figure 8-15 below, costs have been equalised to approximate to £100 / 100km ie: £1/km.

It may at first be considered more appropriate to leave diesel at a typical price of £1.20 per litre and reduce the other energy costs accordingly but the difference is so significant (as shown in Figure 8-14) that comparison becomes meaningless. For example, biomass would need to be less than half its current estimated minimum cost, natural gas costs would need to reduce by a factor of five and electricity would need to be generated at almost no cost due to the distribution costs associated with it.

One benefit of the model is to enable “what if” scenarios to be investigated. It was not possible to equate all pathways to £100 / 100 km, so the primary pathway (C1, C7, and C13) for each option was set as close as possible to this figure. Due to the interactions between the pathways, the model is adjusted in the following order: - Diesel – Electricity – Natural gas – Biomass. In other words, diesel prices are fixed first, followed by the others in the order shown below.



**Figure 8-15 - Cost and Emissions of pathways based on “rising / raised” costs**

- Diesel (£3.07/l)
- Electricity generation (£0.016 /kWhr)
- Natural gas (£0.050 /kWhr)
- Biomass (£0.164kg)

There are two ways of considering the results shown in Figure 8-15 above. Firstly, to compare what energy cost increases are required to “equalise” the pathways. These costs may be considered unrealistic in the current climate with the price of diesel at £1.20/litre, far from the value of £3.07/litre used in Figure 8-15. Electricity generation costs used in Figure 8-15 (1.6 p / kWhr) are significantly lower than current figures for nuclear and renewable electricity. at 2.4 and 4.9 p / kWhr respectively and that is against a current unrealistic diesel cost of £ 3.07 / litre.

Alternatively, the results could be used to consider the necessary adjustments that would need to be made to taxation of energy to equalise the values. However taxation policy is outside the scope of this thesis and not considered further in this chapter, but is addressed to a limited extent in the final chapter when considering recommendations for further research.



8.4.1 Comparison of emissions reduction techniques

One other possible emissions reduction technique is to use hydrogen powered FCV trucks to deliver the hydrogen. Whilst this may be a logical step once a hydrogen economy is established. It is unlikely to offer significant cost benefits until such time as FCV trucks (like other FCV vehicles) are more cost competitive.

Table 8-11 shows the cost benefit of three techniques considered in this research, the use of renewable energy from non nuclear sources (eg: wind / wave etc.), the use of CCS technology and delivery by FCV trucks. Results are shown in Table 8-11below.

Emissions reduction technique	Pence per kg CO2 reduction
Gaseous hydrogen delivery by FCV truck	95.00
Liquid hydrogen delivery by FCV truck	15.00
Use of carbon sequestration in SMR process	7.00
Use of carbon sequestration in Biomass process	7.50
Use of renewable electricity (non nuclear) for electrolysis process	4.27

Table 8-11 Cost benefits of emissions reduction techniques

The results in Table 8-11 can be used as an index in terms of cost benefit of some of the more common emissions reduction techniques. The use of renewable electricity shows the best benefits in terms of cost, but is only related to the electrolysis processes. Carbon sequestration clearly has a benefit for SMR and Biomass processes. FCV truck delivery of gaseous hydrogen does not appear to have any potential in the near future, due to the high cost of the trucks.

8.5 Summary of modelling results

Scenario SC 1 investigated costs for a typical hydrogen pathway. The results showed that the cheapest hydrogen pathway required forecourt diesel prices to reach £1.75 per litre for hydrogen to be cost competitive, and that the depending on the hydrogen pathway, this could increase to almost £4.00 per litre. It also showed that certain hydrogen pathways, ie: electrolysis, actually have higher overall emissions than the diesel reference case when using a whole fuel life cycle boundary. The components of the overall costs and emissions can be sub divided into production and distribution, with production perhaps further subdivided into equipment and energy costs. Variations in equipment costs have not yet been considered so far, but as feedstock cost is

typically 60 to 75% of the overall cost it would seem appropriate to focus on feedstock and energy costs first.

In Scenario SC 3, the typical pathway used in SC1 was reviewed for a range of energy values. Considering the apparent disadvantage of hydrogen pathways from a cost point of view, there appears to be little scope for technology development here except, perhaps the increase of electricity generated from nuclear power or lower cost renewable energy, from wind / wave or solar energy etc.. One possibility is to consider the required cost of renewable electricity to be generated for the local electrolysis pathway (L3) cost. This will be investigated further in chapter 9. Liquefaction of hydrogen appears to show no overall benefit for typical UK pathways for hydrogen powered fleet vehicles and is not considered further. It is felt that unless the hydrogen is required to be stored on board in liquid state it is unlikely to show any benefits in the distribution system.

Scenario SC 2, showed surprisingly that static hydrogen storage was one of the largest single cost components of distribution systems. This is somewhat counterintuitive as one could argue that road tankers are actually storage vessels too. Costs are quoted as 40p and 66p per kg of hydrogen for gaseous and liquid hydrogen storage respectively. Yet considering the capital cost of a gaseous hydrogen road tanker as £103,000 (for 360kg capacity), this would imply that it is significantly cheaper to use road tankers for storage. This is worthy of further analysis, particularly in the case of gaseous hydrogen storage. Perhaps the practice of unhooking the trailers and leaving them as on site storage may be cost effective. This is sometimes used in the industrial sector where relatively small amounts of hydrogen are required. It will also reduce the loading and unloading times in and hence utilisation of the road delivery system. A modified distribution system will be reviewed further in chapter 9. Although gaseous hydrogen delivery by pipeline proved to be the cheapest for all demand and supply chain lengths considered. At lower demands and supply chain lengths, the difference is quite small with increased utilisation of trucks, further reduction in the delivered cost of hydrogen by road tanker could occur.

Carbon capture and storage may have a role to play in future low emissions hydrogen pathways and is worthy of further investigation. Cost reduction requirements to make this process more competitive will be addressed further in the following chapter.

## CHAPTER 9 TECHNOLOGY DEVELOPMENTS

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The initial results from chapter 8 indicate that, in terms of cost, only four pathways can be considered to compete with diesel. These are C1, C2, C7 and C8, and all of these pathways require cost reductions.

In terms of emissions, one might have expected hydrogen to have a significant advantage over diesel. This is dependent on the pathway chosen. The biomass process produced the lowest emissions, but this is highly dependent on feed stock utilised and the method of measuring carbon emissions. The model accounts for the carbon dioxide absorption during the growing process. If first generation biomass crops were used, significant additional land would be required, if second generation waste residues were used, it may improve the overall situation as carbon produced as CO<sub>2</sub> would be accounted for in the main crop, since the biomass is produced from the waste residues. The SMR process is promising, but one could argue that may be more efficient to use the natural gas directly in an internal combustion engine. The emissions viability of the electrolysis process is almost entirely dependent on the electricity production feedstock. Emissions from electricity generation may improve over time (ie: become much lower) if the UK energy mix increases the proportion of electricity generated from renewables, or possibly increases the number of nuclear power station generating electricity.

However, the flexibility of hydrogen still has potential to reduce cost and emissions in the chosen pathways. It may be that future vehicles will be powered from hydrogen from a variety of sources. For example, it is possible that biomass from waste residue would have the combined benefit of producing fuel and reducing waste disposal costs. It may be that new hydrocarbon reserves are higher in gas content and hence the ratio between diesel and natural gas costs may shift in favour of gas having a lower overall cost. Electrolysis has a lot of potential if a relatively cheap and emissions free source of electricity is found. So, overall, the potential pathways for hydrogen are very much bound up in each of its energy production systems.

The results from chapter 8 on the distribution pathways were quite definitive. Although gaseous hydrogen delivery by pipeline was the optimum pathway for all UK scenarios, gaseous hydrogen by road tanker may still have some potential and will still be considered further in this section.

This chapter will focus on cost, emissions and technology developments required to make hydrogen more competitive both economically and environmentally. In this sense, the chapter

defines minimum operating points required for hydrogen to be competitive. The cases reviewed here will be numbered and referred to as “TDs” (Technology Developments).

### 9.1 Competing with the cost of diesel

The conclusion from the modelling work in chapter 8 was that the minimum equivalent consumer price (including taxes) for diesel was £1.75 per litre (pathway C2). To be competitive with diesel at £1.10 per litre, cost reductions equivalent to 65 pence per litre of diesel would be needed, when compared to pathway C2. Table 9-1 shows the equivalent forecourt costs of diesel for each pathway (liquid hydrogen delivery excluded). Using Table 9-1, and deducting the diesel cost, it is possible to calculate the cost reductions required for each pathway. For example for C1 to be competitive with diesel, an equivalent cost reduction of £0.95 per litre of diesel is required (eg: £2.05 - £1.10 = £0.95).

Pathway	C1	C2	C7	C8	C13	C14	L1	L3
cost	£2.05	£1.75	£2.24	£1.93	£3.62	£3.27	£2.10	£4.05
Delivery mode	road	pipeline	road	pipeline	road	pipeline	-	-
Production	SMR		Biomass		Electrolysis		SMR	Elect.

Table 9-1 Typical equivalent diesel costs of each pathway  
(Reproduced from Figure 8-1)

The data used in Table 9-1, is a somewhat cost pessimistic scenario with an assumed supply chain length of 200km and tanker driver utilisation of only 16 hours. Based on demand of 5,000 kg per day, delivery by road tanker is more likely to be a twenty four hour operation, so an increase of the utilisation figure (amount of time trucks are delivering per day) and a more realistic supply chain length of 100km could be considered. This would have the effect of reducing the delivery costs of the centralised pathways. For the gaseous road tanker deliveries this would reduce the cost by about 11pence with respect to the equivalent diesel cost on the C1, C7 and C13 figures shown in Table 9-1. For the pipeline method the reduction is much less, being 1 to 2 pence for pathways C2, C8 and C16. This is due to the higher utilisation figure only applying to road tanker deliveries. If the utilisation were to be increased to twenty four hours, this would reduce the C1, C7 and C13 pathways by a further 3 pence with respect to the equivalent diesel cost.

This analysis shows that the supply chain distance and type need to be considered carefully. Table 9-1 reports a differential of 30 pence between C1 and C2, just by increasing truck utilisation and shortening the supply chain this can be reduced to 16 pence, almost halved. With a large cost



differential between diesel and hydrogen this may not be relevant but as the cost differential becomes smaller, modelling the delivery system will help show which system has optimum costs.

### 9.1.1 TD 1 – Storage cost reductions

One of the largest cost components of the hydrogen distribution system determined in the modelling results in chapter 8 was on-site storage (£0.40 per kg). However there is evidence that this can vary widely. The CUTE costs ranged from £0.23 to £0.71 / kg of hydrogen (Binder M and Faltenbacher M, 2006, Fig 3, page 18). Whichever figures are used, storage is a significant contribution to the overall cost of delivery, indeed the model results in chapter 8 show static hydrogen storage costs as being higher than the mobile storage costs (ie: the road tankers). If all the costs associated with transportation are removed, the static cost of storage appears to be somewhere in the region of 3 to 4 p per kg of H<sub>2</sub><sup>35</sup>.

One possible approach is to investigate the use of hydrogen delivery trailers as temporary on site storage containers. This has two potential benefits, firstly it seems to offer cheaper storage and secondly it will reduce the onsite loading and unloading time as trailers are simply hooked up to trucks. It removes the need for the careful loading and unloading rates referred to in CUTE and should reduce compressor power requirements as there is one less stage required for fluid transfer. In this system, the tanks would form a new mobile modular storage system.

It is difficult to obtain accurate data on storage transportation equipment costs. Amos (Amos W, 1998), provides some useful support data. Although this paper and some of the data provided is relatively dated, this is not new technology and hence, so long as costs are adjusted to the present price levels, should be reasonably indicative.

It would appear that a reasonable cost for a 460kg hydrogen trailer is \$340,000 (Amos W, 1998, p34), this equate to approximately £222,000 when converted to UK Sterling and adjusted for inflation. At 6.6p<sup>36</sup> per kg of H<sub>2</sub>, this is significantly less than the most optimistic of onsite storage costs. It also allows the loading and unloading time in the model to be reduced from three hours to perhaps just one<sup>37</sup>, delivery is now just a matter of just delivering the full trailer and collecting the empty trailer with no waiting time and using the same tractor unit.

<sup>35</sup> Based on model capital cost of £103,000, 2% p.a OPEX cost, 25 CAPEX life.

<sup>36</sup> This is an estimate of the daily capital cost assuming an operating life of 20 years, daily refill, 460kg capacity ie: £222,000/(20 x 365 x 460) = 6.6 pence per kg of hydrogen

<sup>37</sup> This is an estimate based on the author's experience of tanker filling systems. This allows for time to park the full tanker in position, connect the empty tanker and complete all paperwork and site access requirements.



If the results in Table 9-1 were adjusted for increased utilisation, shortened supply chain and storage cost reductions discussed here, the revised figures would be as shown in Table 9-2. This enables hydrogen costs to be reduced significantly and the cheapest pathway, although still more expensive than diesel at £1.10 per litre, it is worthy of note that forecourt diesel costs reached a peak of £1.30 per litre 2008.

Pathway	C1	C2	C7	C8	C13	C14	L1	L3
cost	£1.65	£1.53	£1.84	£1.71	£3.18	£3.05	£1.86	£3.84
delivery	road	pipeline	road	pipeline	road	pipeline	-	-
production	SMR		Biomass		Electrolysis		SMR	Elect.

**Table 9-2 Equivalent diesel costs for each pathway, storage and transport cost reduction**  
(Loading and unloading 0.5 hrs each, storage cost = £0.05 / kg of hydrogen, Utilisation 20 hours, supply chain 100km, all other data as per Table 9-1)

Interestingly, a similar approach is discussed by Yang and Ogden in their work and justified for small scale facilities where demand is low, they state that *“this makes them suitable for hydrogen markets that have small delivery requirements”*. But that only considered transportation at the relatively low pressure of 160 bar with on site booster compression (Yang C and Ogden J, 2006a, p270). However this research model appears to show this method as being viable for all demands of 500 to 5,000 kg/day.

### 9.1.2 TD 2 – Lowering the cost of localised production

Another area with potential for cost reduction is within the two localised pathways that have been considered in this research. Localised Steam Methane Reforming process (L1), using natural gas, and conversion of water into hydrogen and oxygen by electrolysis (L3). Both processes are used in centralised pathways and the cost issues discussed here mainly relate to economies of scale. Unfortunately, neither pathway is cost competitive with diesel at present, as shown in Table 9-1, but both obviate the need to transport hydrogen completely. It is perhaps a measure of the difficulties of producing hydrogen cheaply at small scales of production that the centralised pathways are cheaper, even when including the considerable cost of delivery.

As there is no supply and distribution system associated with localised production (because they utilise existing supplies of gas and electricity), potential cost reductions are mainly limited to capital cost of equipment and energy costs, although these would logically apply equally to both centralised and localised production. However, on site storage was a significant component cost in chapter 8 and hence the proposed technology change in section 9.1.1 is still equally relevant. The

results in this section therefore take into account the cost reduction potential identified in the previous section.

#### **9.1.2.1 Pathway L1 – localised production by SMR**

This pathway is reasonably cost competitive with the most cost effective centralised production pathway C1. From Table 9-2, the cost difference between the two pathways is 21 p / litre of diesel equivalent. This cost difference is due to the additional costs associated with localised production minus the cost of transportation. In the model, both the cost and quantity of feedstock (natural gas) are equal for both pathways (C1 and L1), hence the cost increase in production relates directly to the more expensive cost of small scale production process plants compared with larger units (economies of scale). Thomas considered the potential economies for large volume small scale production units in his paper titled "Affordable hydrogen supply pathways for fuel cell vehicles" (Thomas C et al., 1998), so the concept is established. The model results show that the typical operating cost, excluding feedstock, of small scale hydrogen SMRs are approximately 40% of the overall cost of the hydrogen. For large scale centralised production units, the equivalent value is approximately 13%, significantly less.

Although there may be some potential cost reductions here for small scale production, this research model reports that for the localised pathway (L1) in Table 9-2 to reach the centralised pathway (C1) value of £1.65 per litre of diesel equivalent, a 40% reduction in capital cost would be required. Considering that the capital cost value used in the model was provided by Caloric, who specialise in the supply of such small scale reformers (VonLinde F, 2008) it should be considered accurate, but whilst the Caloric SMRs are factory built, they cannot be considered production line items. Perhaps there is potential here for reductions in capital costs but whether a reduction of 40% is achievable is not clear from these results and would require further more detailed analysis.

Although not related to costs, another obstacle for this pathway is that fact that SMR units still produce a significant amount of CO<sub>2</sub> and that the technology for carbon sequestration is not suited to localised SMRs, due to the need for a permanent storage facility for the carbon dioxide. This would limit any potential for emissions free hydrogen from this pathway. It would therefore seem appropriate not to consider this pathway further at this stage.

### 9.1.2.2 Pathway L3 – localised production by electrolysis

This was the most expensive pathway identified in Table 9-2 and perhaps could reasonably be excluded as a pathway with further cost reduction potential, particularly when there are other potentially more viable pathways. Chapter 8 also showed that electrolysis does not appear to be viable on the basis of emissions either. However there are a number of reasons why this pathway is worthy of further consideration:-

- It offers the potential of truly emission free hydrogen if the electricity supply system is fully decarbonised.
- Although a significant user of electricity, it offers the potential for on site electricity generation, eliminating the significant cost of distribution and transmission losses (typically 8%).
- The process of electricity generation and direct conversion to hydrogen helps eliminate one of the criticisms related to renewable energy (intermittent wind, sun etc.).
- Electrolysers are relatively simple process units and may have greater potential to benefit from cost reductions by using factory built production line techniques, to produce large volumes of small capacity electrolysers.

The first three of the above reasons can be observed in the chapter 5 case study on the Camelford and district bus project, which was one of the projects which failed to materialise, due to lack of funding.

Cost reductions in L3 focus on the use of entirely renewable sources of electricity, generated locally and the potential economies of scale in production unit manufacturing. The model results show that the typical operating cost, excluding feedstock, of small scale electrolysers are approximately 27% of the overall cost of the hydrogen. This is a slightly smaller proportion than the localised SMR pathway (L1), which is typically 31%, making it necessary for even greater cost reductions in capital equipment costs to make this pathway competitive. Considering that energy costs are 73% of the total hydrogen cost it would seem appropriate to consider the required cost reductions in electricity generation as well as capital costs.

There are many different methods of generating electricity from renewable sources and nuclear power. However nuclear electricity generation is not suitable for local production (with transmission) and hence not considered further here. The Royal Academy of engineering addressed these issues in a publication on the cost of generating electricity (Ruffles P, 2004).

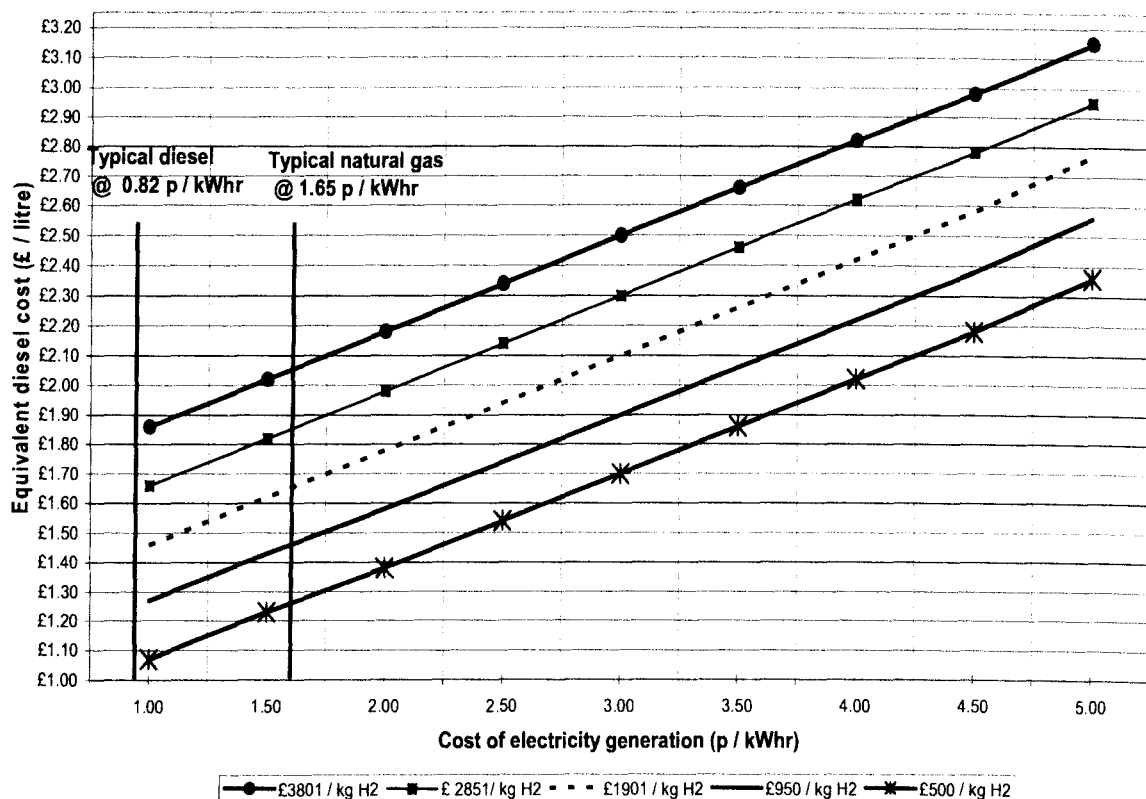
These costs are shown in Table 9-3, they do not include the cost of transmission, or standby generation, as neither are required for pathway L3.

Source	Cost (p / kWh)
On shore wind farm	3.7
Offshore wind farm	5.5
Wave technology	6.6

**Table 9-3 Cost of generating renewable electricity  
(Ruffles P, 2004)**

The list is not exhaustive and there are many other sources of renewable energy, for example tidal, solar and hydro. These methods of electricity generation are considered outside the scope of this thesis. The analysis in this section is intended to identify necessary generation costs to make this pathway competitive.

The model results to date use a typical capital plant cost equivalent to £3,800 / kg of H<sub>2</sub> based on data collected from various sources. Figure 9-1 plots the equivalent price of diesel against electricity generation costs for a variety of capital plant costs. The vertical axis represents what the forecourt price of diesel would have to be for this specific pathway (L3) to be competitive with diesel. The horizontal axis represents the generation cost of electricity, although the model calculation takes into account the additional cost factors such as transmission, distribution, profit etc. the graph lines are linear and represent four different capital costs of the production plant on a cost / kg of hydrogen basis. As the lines are linear, they can be interpolated for a wide variety of capital plant costs.



**Figure 9-1 Cost of pathway L3 for varying electricity generation and plant capital costs**  
Y axis represents equivalent diesel price of the hydrogen pathway  
X axis represents electricity generation cost  
Graph lines represent capital cost of production equipment

If renewable energy could be produced at a cost of 1.5 p./ kWh, and capital equipment costs reduced to £500 / kg H<sub>2</sub>, it is possible that pathway L3 may become viable with diesel at approximately £1.20 per litre. Neither of these are likely scenarios in the present climate. With current typical costs for an electricity onshore wind farm of 3.7 p / kWh, and capital equipment costs of £3,800 / kg H<sub>2</sub> it is clear to see that at present this is an unlikely scenario.

A number of issues and technology developments have been addressed here. The SMR pathway (L1) seems to require significant capital cost equipment reductions and the localised electrolysis pathway (L3) seems to require both capital cost reductions and electricity generation costs to be reduced. It would appear therefore that in the near future we are limited to centralised production pathways.

Although these centralised pathways are still more expensive than the diesel reference case, the cost difference is less and hence there may be potential here for technology developments to make hydrogen both economically and environmentally viable. The issue is that the most cost effective method is centralised SMR production by pipeline (C2). Whilst reductions in production cost are



possible, as a mature technology it seems unlikely that significant reduction can be achieved with this process. It therefore follows that focusing on pathway reduction costs are desirable and this will be discussed later in section 9.1.4 The other issue associated with SMR production is emissions and this will now be addressed in the next section on Carbon Capture and Storage (CCS) technology.

### **9.1.3 TD 3 – Emissions reduction with CCS**

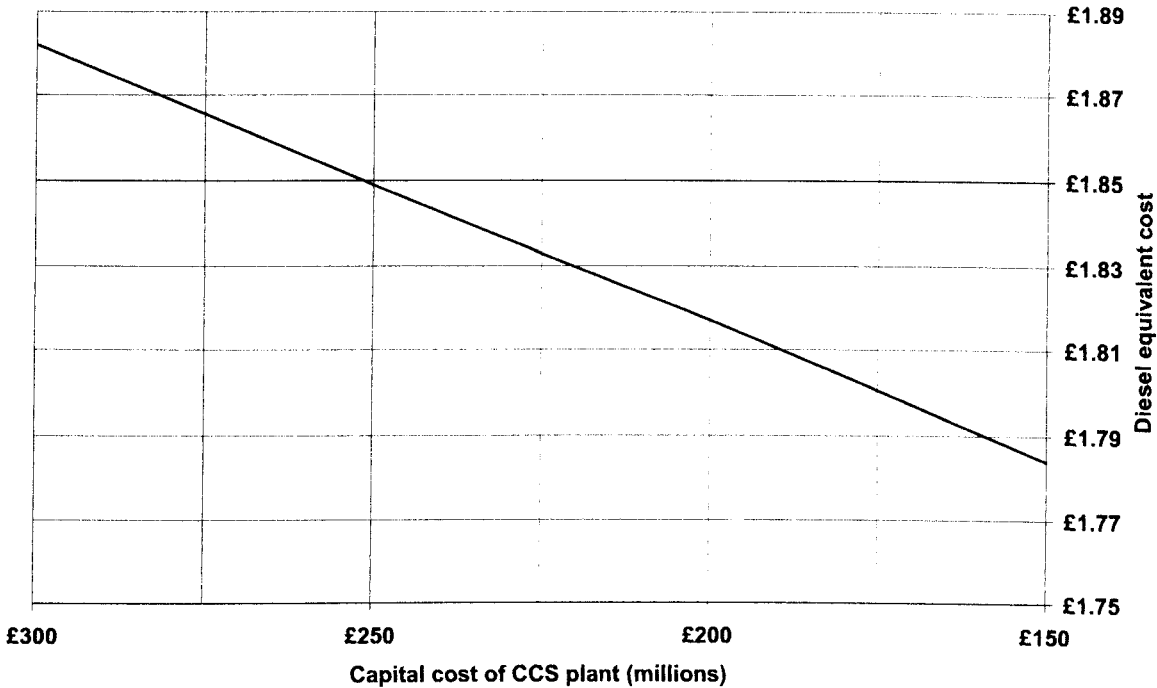
So far in this chapter, technology developments have focused on possible cost reductions, with no impact on emissions. Carbon Capture and Storage (CCS) technology or Carbon Sequestration as it is also known, is a process which removes carbon dioxide from the process waste gases and permanently stored, usually in underground caverns. The technology is not just applicable to hydrogen processes as it is being considered as “clean up technology”, which can be used on other processes, such coal and gas fired electricity generating power stations.

The model used in this process has the facility to calculate the effect of CCS technology on the SMR (C1, C2, L1) and biomass (C7, C8) hydrogen production processes, but not from electricity generation, which is used mainly in the electrolysis hydrogen production process (C13,C14, L3). As this technology development focuses on the CCS process only, results here are reported merely as CCS results and hence independent of the pathway used, although pathway C1 was used for all calculations.

It has been difficult to obtain accurate capital equipment costs and efficiencies due to CCS being a relatively new technology. The capital cost data used in this model is taken from the US DoE hydrogen program spreadsheets (US DOE, 2009) If the technology is broken down into it's two component parts, “capture” and “storage”, it is perhaps easier to understand where estimates are most appropriate. The “capture” technology, being an industrial process can be reasonably well estimated in terms of cost of equipment, energy usage etc. It is largely independent of location, but would logically be sited adjacent to the hydrogen production facilities. The “storage” element is more difficult to estimate due to the specific geographic requirements, such as “is there a suitable storage facility nearby”? Offshore sites are being considered, which would perhaps be more expensive than onshore? How is the CO<sub>2</sub> transported to the storage site, by pipeline? If so, this would then introduce the uncertainties in estimating pipeline costs that hydrogen pipeline estimates suffer from, ie: compression, type of terrain etc.

For these reasons a simplistic approach has been taken to the results discussed here. The cost of CCS is reported for a variety of capital costs, regardless of the component breakdown of such costs (eg: capture or storage etc.). More detailed analysis is considered outside the remit of this research. All other variables affecting the total cost of CCS have been based on the same values for CAPEX, OPEX, operating costs and energy costs etc as used in the hydrogen production process.

For simplicity, results have again been reported as equivalent diesel costs to enable easier analysis of the impact of the cost increase of this technology. Results shown in Figure 9-2, are based on current typical diesel price forecourt price of £1.10 per litre. For the pathway C1, this results in an equivalent diesel price of £1.65 per litre (refer to Table 9-2), without CCS technology.



**Figure 9-2 Cost of CCS technology**  
Typical plant capacity 400,000 kg CO<sub>2</sub> per day  
CCS recovery efficiency of 90%

Depending on the capital cost of equipment, this technology would add between 13p to 23p to the equivalent cost of diesel. To put these costs into context, the capital equipment and storage costs here are much more significant than compared with a typical hydrogen production process, which are more significantly affected by energy costs, than capital equipment costs as reported earlier. The most optimistic cost forecast, still places hydrogen approximately 60p / litre of diesel equivalent

more expensive than diesel. The next question is to review what levels of carbon reductions are achieved by using this technology and hence the cost effectiveness.

The diesel reference case at £1.10 per litre states emissions of 4.16 kg CO<sub>2</sub> per km of bus travel. The pathway C1 (without CCS) costs £1.65 per litre of diesel equivalent and has emissions of 2.63<sup>38</sup> kg CO<sub>2</sub> per km of bus travel. The pathway C1 (with CCS) has costs in the range of £1.78 to 1.88 per litre of diesel equivalent with emissions of 0.56 kg CO<sub>2</sub> per km of bus travel.

It is clear that CCS technology has the potential to sufficiently reduce emissions, but perhaps not quite to zero as this is likely to be unachievable due to delivery emissions which are very difficult to capture. To put this into context, the cleanest cars today report values in the region of 100g CO<sub>2</sub> per km (often, but not always with only one passenger on board). In terms of emissions, one hydrogen bus journey would equate to six car journeys (based on the above figures), but a diesel bus would equate to more than 40 car journeys. Cost benefit analysis is often used to evaluate such technologies. Using the model reported values below, hydrogen without CCS costs 35p per kg of CO<sub>2</sub> reduction, whereas hydrogen with CCS costs an additional 6p to 11p per kg of CO<sub>2</sub> reduction. One could argue that CCS is better value in terms of emissions reductions, than the actual conversion to a hydrogen pathway.

- Diesel bus travel at £1.10 per litre and emissions of 4.17 kg of CO<sub>2</sub> per km. Although recent figures from DEFRA give a lower value of approximately 1.1 kg of CO<sub>2</sub> per km for London buses (DEFRA, 2008, p21). It is based on 81.8 g CO<sub>2</sub> / passenger km and an average of 13.5 passengers.
- Hydrogen bus travel at the diesel equivalent cost of £1.65 per litre and emissions of 2.63 kg of CO<sub>2</sub> per km
- Hydrogen bus travel (with CCS) costs between £1.78 and £1.88 per litre and emissions of 0.56 kg of CO<sub>2</sub> per km

The results reported here are specific for the SMR pathway C1, results would vary for other pathways such as biomass dependent on type of feedstock.

### 9.1.4 Hydrogen pathway optimisation

The technology developments reviewed in this chapter will have some effect on optimisation of hydrogen pathways, TD 1 and TD 2 focus on cost reductions, whilst TD 3 focus on emissions reductions at the expense of cost. Due to the variety of ways in which hydrogen can be produced,

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<sup>38</sup> The CCS costs are largely independent of the upstream hydrogen production process (ie: SMR, biomass etc.) but the overall emissions are not, although the differences are sufficiently close for this analysis and hence disregarded.

stored, transported and used, there are many other options which can be considered. Some may be worthy of further study but are not considered here for reasons given below.

It is reasonable to assume that mature hydrogen production technologies are relatively well developed in terms of cost effectiveness, in terms of both capital equipment costs and energy efficiency. The “add on” technology of CCS has been reviewed to a limited extent in TD 3. Newer hydrogen production technologies such as thermal separation may have some potential but have not been considered in this research, for a variety of reasons, mainly because the model used is not suitable for developing technologies at present. Production costs can also be reduced by the use of large volume “product line” process plants, where cost reductions can be achieved due to manufacturing quantities rather than economies of scale associated with larger volume production facilities. This could be used to achieve the cost reductions potentials discussed in TD2.

Storage cost reductions were addressed in TD 1 as this proved to be a significant proportion of the overall cost of storage and distribution. Although model cost values were real, based on the CUTE project, it is clear that there is potential here for cost reduction and, perhaps the options considered in TD 1 may have a part to play in the overall cost reduction process.

The transportation methods reviewed here are also relatively mature technologies and hence limited potential for cost reduction due to technology developments. Compression, pipelines, road tankers have all been used for hydrogen (and other fuels) for many years and it is difficult to foresee significant technology developments occurring in this area in the future. One possible exception is the use of solid storage for hydrogen which may have future potential. At present the materials technology is at the R&D / early demonstration stage and hence it is not clear what type of final distribution method might evolve. Until such the distribution method becomes more apparent it is not appropriate to review the technology developments here.

Detailed analysis of other possible developments such as vehicle costs and energy taxation, are considered outside the scope of this research, but worthy of a brief review as both can contribute to the viability of a future hydrogen economy.

### **9.1.5 Vehicle cost improvements**

In this research, the cost of a hydrogen powered vehicle has been excluded from modelling results. At the start of this research, in 2002, the BMW 750H, hydrogen powered internal combustion engine driven vehicle was being presented as available for purchase in the “near future”. It is now 2010 and the author is not aware of any hydrogen powered vehicles, either FCV or ICE being

commercially available in European car showrooms. It is therefore difficult to report any real costs for hydrogen powered vehicles at present. Perhaps the nearest “real figure” is in California, where Honda are making 200 Honda Clarity FCX fuel cell vehicles available for lease at a cost of \$600 per month with a lease period of 3 years (Honda, 2009). It is unlikely that this reflects the true cost of the vehicle including maintenance for the period in question. With California hydrogen fuel costs are in the region of \$5.00 to \$8.00 per kg (Oakland A, 2009), the choice of a Honda FCX is clearly a lifestyle, rather an than economic choice.

Presumably Honda has chosen California as a test bed region with a reasonable number of hydrogen filling stations. However, although there are currently twenty seven filling stations in California, there only a couple of filling stations in the neighbouring states of Arizona, and Nevada (NHA, 2009). The Honda's vehicle range is claimed as 240 miles, this means the vehicles are still effectively limited to travel in California. This is one of the reasons why it is appropriate to consider fleet vehicles for trials, which can be supported by one common centralised re-fuelling facility as the first likely large scale transition vehicles and why fleets have been integral to this research.

By comparison, the CUTE review earlier reported the buses as costing £850,000 each with the Fuel Cell component alone costing £120,000.; this cost is about the same as a typical diesel bus price (Coney A, 2004). Although the CUTE buses can be considered as prototypes, based on the above figures, hydrogen FCVs would need to have their capital costs reduced by a factor of seven to be cost competitive, which is possibly feasible, considering that this technology is still being developed and not mature.

The additional efficiency of FCVs compared to an ICE has already been taken into account in the modelling, with the fuel efficiency of each type of vehicle used in the calculations. It is interesting to compare the actual fuel consumption results of CUTE with the Honda fuel consumption figures. By comparing the ratio values in Table 9-4 below, it is clear that the Honda vehicle has a significant improvement in economy compared to the CUTE buses. It should be note that the buses on the CUTE project were not optimised in terms of efficiency. Subsequent buses ordered for a new fleet for Hamburg claim to use 50% less hydrogen (Fuel cells bulletin, 2009).



	<b>BUS fuel consumption</b>	<b>Private vehicle fuel consumption</b>	<b>Ratio (Bus / PV)</b>
<b>FCV</b>	0.25 kg hydrogen / km	0.01 kg hydrogen / km	<b>25</b>
<b>Diesel</b>	0.368 kg diesel / km (6.4 mpg)	0.036 kg diesel / km (64 mpg)	<b>10</b>

**Table 9-4 Fuel efficiency comparisons**

The Honda value, if borne out in vehicle trials, would effectively reduce the bus FCV consumption figures significantly and could be used to effectively reduce the cost of the fuel or mitigate the capital cost of the vehicle. The fuel efficiency of hydrogen FCVs is an important factor when measuring the viability of FCVs from an economic point of view. For example if the model had used the most optimistic fuel consumption figures from the CUTE project (Hamburg at 20.4kg H<sub>2</sub> / 100km), the equivalent diesel cost for pathway C1 reported in Table 9-2 would be £1.48. Furthermore, if the Honda FCX claims were realistic and translated to FCV buses, the C1 cost would reduce to £1.05, to produce parity with diesel.

There are three elements to improving the economic viability of hydrogen powered FCVs, The cost of the vehicle, the cost of the hydrogen and the efficiency of the vehicle in terms of fuel consumption. Although this research has briefly looked at vehicle costs in chapter 2, the main focus has been on been on the cost of hydrogen. Improvements in fuel efficiency will also help to bring down the cost per km travelled and may prove to be just as important in delivering hydrogen as cheaply as possible.

### **9.1.6 Other alternative technology developments**

Although this research focuses on fleet vehicles, the technology issues associated with motive power for vehicles are the same whether for private vehicles, buses, taxis, lorries or even trains. It appears that the choice of motive power is between an internal combustion engine and an electric motor. Both are mature technologies and whilst there will no doubt be continuing improvements in efficiencies for both, these are likely to be incremental steps rather than significant technology breakthroughs. Considering the significant advantage that the electric motor has over an ICE in terms of efficiency, it is reasonable to assume that in efficiency terms, the preferred method of motive power in future vehicles is likely to shift towards electric motors.

In chapter 2, the focus was on the choice of fuels for vehicles rather than the engine technology. One could perhaps argue that there is likely to be more potential for future technology developments in fuel and energy storage systems rather than motive power. These issues can be subdivided further into types of fuel; ie: hydrocarbons and the alternatives, and energy storage, ie: electricity, hydrogen, and also in what form – gaseous, liquid or solid state.

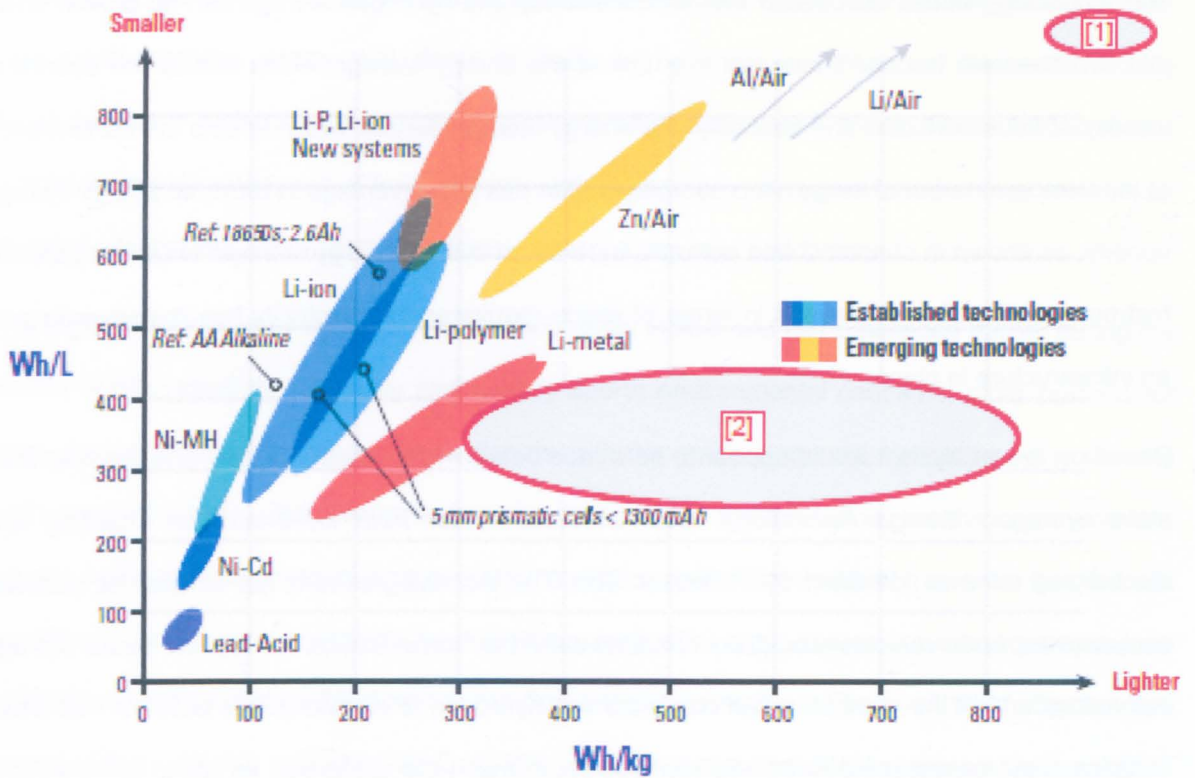
The argument for or against hydrocarbons is currently topical and has developed further during the course of this research. Primarily and notably due to environmental concerns, other reasons for change away from hydrocarbons have also risen in the political agenda, typically energy security and energy shortage. This research focuses only on road transportation, but the arguments are equally valid for other users of energy such industry or residential use etc. It may be that it is not possible to switch over to entirely renewable sources of energy, due to our inability to produce sufficient quantities. David Mackay applies this holistic approach in his book titled "Sustainable energy without the hot air" (MacKay D, 2009). One conclusion that Mackay seems to suggest, is that perhaps there is not sufficient renewable energy for all our needs based on current demand, this is of course only one view., but if this is the case, technology issues associated with on board storage of energy may mean that some vehicles in the future will continue to be powered by hydrocarbon fuels for quite a long time. Conversely, it would be desirable if hydrocarbons were used in static rather than mobile applications or at least used to produce hydrogen for mobile applications as it would then be possible to use CCS technology to reduce emissions.

If we could easily store sufficient energy on board the electric vehicles, with an efficient refuelling infrastructure in place, it would seem the ideal solution (providing the electricity is generated from decarbonised sources). Future non hydrocarbon technology developments need to focus on the issue of on board energy storage. The two main non hydrocarbon storage competitors can be summarised as on board electric energy storage and on board hydrogen storage; ie: battery versus hydrogen plus fuel cell. This is an obvious simplification, but it highlights the core technological choice. However there are important variations of the two core technologies. Electric energy storage is not just limited to batteries; other devices such as capacitors can also be used. Equally, hydrogen can be stored in gaseous, liquid and potentially solid state. Liquid hydrogen has to some extent been excluded in chapter 6, and it is falling from favour (the author is not aware of any current hydrogen vehicles storing liquid hydrogen on board since the BMW 750H). Solid state hydrogen has not been evaluated in this study but clearly needs to be considered as a future possibility.

The technology issues associated with both electricity and hydrogen storage can be broken down into two separate issues. These are the cost of the energy storage which affects the economic viability of future vehicles and secondly, the energy storage density which affects the performance of the vehicle in terms of range. At present hydrogen has the advantage in terms of energy storage density, as shown in chapter 2 and perhaps, in terms of cost of energy storage. However gaseous hydrogen storage has limitations in terms of space requirements. Electricity has the advantage of an infrastructure in place.

Based on this analysis it would appear to be a race between the electric battery and possibly solid state hydrogen storage technology. Both of these suffer from limitations on charging and discharging rates as identified by Professor Guo. The technologies may not actually be mutually exclusive as both vehicles would be fundamentally the same except for the on board storage technology and of the need for a fuel cell to convert hydrogen to electricity. It is possible that future vehicles could be designed to be interchangeable, in much the same way as some current petrol vehicles are converted to run on LPG.

The issues discussed here focus more on private vehicles rather than fleet vehicles. Storage weight, space, charging rates and to a lesser extent fuelling infrastructure; are less of an issue for fleet vehicles such as buses. The issue of space and weight are particularly relevant to the hydrogen versus the battery debate. Energy storage density can be interpreted in two ways, either by mass or volume. Cars and fleet vehicles have different requirements in this respect. Batteries tend to be smaller and heavier than hydrogen equivalents in terms of energy stored as shown in Figure 9-3 below). This has both advantages and disadvantages for private vehicles. Smaller sizes are desirable for space reasons but weight carries a penalty, in that it increases the mass of the vehicle as well creating weight distribution problems for designers. By comparison, the CUTE buses stored their hydrogen in cylinders on top of the buses, less of an overall weight issue but comments were made about inferior handling by the drivers during the trials, possibly due to weight distribution.



**Figure 9-3 Energy storage densities of batteries and gaseous hydrogen**  
(Nexergy, 2009)

- [1] Denotes typical high pressure gaseous hydrogen (700bar) carbon composite storage systems as detailed in Figure 2-1 (Eberle U et al., 2006)
- [2] Denotes typical gaseous hydrogen steel storage systems as detailed in Figure 2-1 (Eberle U et al., 2006)

It would therefore seem logical to focus future research on the development of both electric and hydrogen storage systems in parallel as it is possible that both may have potential for different applications. It may be that in future vehicles both technologies will exist, for example, batteries for small vehicles and hydrogen for larger vehicles.

### 9.1.7 Energy taxation policies

All comparisons, results and modelling in the previous chapter, were based on diesel and hydrogen being “tax neutral” (i.e. the cost was nett of any fuel taxes). Regardless of the reasons for change, external influence is required. In this case, it seems that the “technology pull” scenario, whereby new technologies evolve due to some clear benefit, is unlikely to occur. A more likely case is the “technology push scenario” whereby a new technology is adopted due to the benefit of incentives, in this case energy taxation. In practice, a change away from hydrocarbon based energy to hydrogen, will require taxation adjustment in favour of hydrogen. This may be combined with regulation, requiring city based vehicles such as buses to run on non hydrocarbon based fuels.

Whilst detailed analysis of taxation policy is considered outside the scope of this thesis, the model does have the facility to calculate the results of “what if” scenarios. Diesel, natural gas, biomass as well as the four most common sources of electricity generation (nuclear, gas, coal and renewables) costs can all be adjusted to determine each pathway cost. For example, in chapter 8, SC1, the hydrogen cost equivalent price of diesel is plotted against all hydrogen pathways. The inference in chapter 8, was that diesel, and hence the price of barrel of oil, would need to reach these relatively high values for parity. It is equally possible that the cost increases could be achieved with additional taxes on hydrocarbons or through a combination of these fuels.

If energy taxation was applied to hydrocarbons and used to subsidise hydrogen it would be reasonable to assume that the cost difference between the values in the scenario could be reduced. For example, it was reported in section 9.1.5, that pathway C1 could be as low as £1.48 per litre of diesel equivalent. If 50% of the fuel used in vehicles were diesel and the remainder hydrogen, and with diesel at £1.10 per litre, one could argue that an additional tax of only 19 pence per litre is required on diesel to achieve parity  $((£1.48 - £1.10)/2)$ . The problem with this strategy is that with initial uptake of hydrogen vehicles being low, a relatively small diesel tax would benefit hydrogen significantly, but as hydrogen uptake increases, so does the diesel taxation requirements to achieve the same level of subsidy.

Energy taxation is a complex subject, but may be an important factor in perhaps tipping the balance in favour of hydrogen in the future, particularly in the case of energy intensive processes such a hydrogen production from electrolysis, where unrealistically low energy costs are required to make the pathway competitive (refer to Figure 9-1). However it would seem desirable that technology developments are needed first to reduce both the cost of hydrogen and to lower the emissions from some pathways before energy taxation can be considered as this will minimise the tax requirement on diesel to close the cost differential. Alternatively, the demand side needs to be developed as mentioned earlier in this section when referring to “technology push scenarios”

## **9.2 Summary of technology developments**

The research in this chapter on technology developments has deliberately avoided new production technologies, as well as vehicle technology developments (apart from some discussion of fuel efficiencies), as both are considered outside the boundaries of this research. It has reviewed the cost reduction requirements of future technology developments of existing production technology



for localised production pathways as this may be an important factor in developing future localised hydrogen production systems even though it may not be competitive at present.

Energy costs and the interactions between prices are a complicated subject and detailed analysis is not part of this research. In this chapter the cost reduction requirements of electricity generation were reviewed, mainly due to the need to improve the cost of hydrogen generation by electrolysis as this is a potentially viable pathway from an emissions and production point of view.

Energy storage was identified in chapter 8 as a major contributor to the cost of the supply and distribution system. The option of using the road tankers as storage vessels is not new, as other researchers have used this idea. The difference in this research is that it appears to be viable for all demands rather than just small niche situations. It is difficult to understand why hydrogen tankers should be cheaper than static storage systems, although the limited amount of information found in the literature review as part of this research seem to concur on this and hence the reason the values were used in this research model.

One important advantage which should not be underestimated with the use of mobile storage tankers for static applications is that it reduces the energy requirement for compression required to transfer the hydrogen between tanks and consequently it also reduces the transfer time, improving truck utilisation and reducing labour costs.

Gaseous hydrogen trucks are “modular” in that they are a series of tanks or cylinders. It may be that if they could be designed to be individual modules, they could be developed to become “replaceable cylinders” and then connected direct to the buses, similar to the Calor gas scenario discussed earlier in this research for solid state hydrogen cylinders.

An important element of this research has been the modelling of the pathways results can vary according to a wide range of factors, particularly for the road tanker delivery systems. Truck utilisation has been shown to reduce costs and other factors such accurate modelling of the delivery system from terrain to truck speeds all have a part in modelling accurate delivered hydrogen costs.

Carbon Capture and Storage technology was reviewed in terms of cost reductions of capital equipment only as this is purely for emissions reductions, and needs to be achieved for the relevant pathways at minimum cost. Although this review does not consider how cost reductions can be achieved it does identify where technology needs to optimise, in terms of capital costs and

hence a useful measure when considering the current costs for SMR and biomass production technologies.

Finally, it was shown that energy taxation may be viable to close any outstanding gap between the cost of hydrogen and diesel. Considering that taxation is a potential issue for policy makers in terms of public acceptance, it would logically be kept to a minimum level and hence the need for other technology developments to be achieved first.

## CHAPTER 10 SUMMARY

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At the end of chapter 1, the lack of an established hydrogen supply and distribution system for ground transport was identified as a potential obstacle to a future hydrogen energy system. This was further complicated by the number of possible forms that such a system may take, ie: centralised / localised production, transportation in gaseous / liquid and solid state etc. The aims of the research in this thesis has been to investigate a number of the possible pathways that might allow a future hydrogen energy system to develop and if possible reduce the viable options, enabling more detailed analysis of specific pathways. The key points drawn from the research in this thesis are:-

- Hydrogen is possibly competitive with diesel on cost of production, but not on cost of distribution. Overall this makes hydrogen pathways more expensive than diesel.
- Localised production of hydrogen is not competitive with centralised production at present, so it is likely that a hydrogen distribution system is going to be needed. It is possible that future localised production systems may be competitive but would depend on reduced capital equipment costs.
- The cheapest hydrogen pathways may not be the pathway with the least emissions.
- The storage of hydrogen appears to be a major part of distribution costs.
- Gaseous hydrogen delivery by road tanker can only meet small niche markets
- Transporting hydrogen in liquid state is not viable for any supply chain lengths and demands in the UK (within the boundaries of this model i.e.: 200km and 5,000kg / day).
- Gaseous hydrogen delivery by pipeline may be needed if a reasonable uptake is sought. This would require significant investment.

The aims and results of this research were stated in terms of costs and emissions and the author feels that in terms of cost, this research has been successful with respect to identifying the cost competitiveness level of hydrogen (typically £1.25 to £1.50 per litre of diesel equivalent) and more importantly the areas where cost reductions may be required to make hydrogen comparable to diesel. The environmental benefits of hydrogen have been researched and the case for changing merely on environmental grounds is only justified if the more expensive pathways are chosen. This effectively links the two issues of cost and emissions. In chapter 9 it was shown that it is possible to quantify the cost of reduction in terms of £ / kg CO<sub>2</sub> reduction and this may be required when evaluating hydrogen which is produced from any sort of hydrocarbon source.

The large number of potential pathways identified in chapter 6, have been reduced significantly and the exclusion of liquid hydrogen is one such example whereby accurate modelling could have



avoided the mistake of supplying liquid hydrogen storage without the demand and hence the losses incurred in the CUTE liquid hydrogen delivered by truck case in London. The need for hydrogen pipelines for large scale uptake is potentially a major obstacle to a future where all vehicles are run on hydrogen as installing a hydrogen pipeline network in the UK is no small task. The alternative to this is to make the hydrogen at the point of loading which is not difficult technically, but at present this is not an economically viable solution. The fact that gaseous hydrogen delivery by road tanker is only suitable for small scale demonstration projects such as CUTE is an important point and a similar conclusion was reached by Shayegan when a practical limit of 3,500 kg / day was suggested (Shayegan S et al., 2009). Some of the findings from this research will now be summarised in more detail.

### **10.1 The cost and emissions associated with production**

Results in this thesis have shown that the major cost and emissions associated with a hydrogen energy system are due to production (refer to chapter 8). Although hydrogen is not yet competitive in cost for all pathways, and in emissions for some pathways, it is possible that in the near future diesel prices may rise to the point where the situation may change.

The Office of National Statistics (ONS) reported a figure of £1.26 per kg of hydrogen (refer to chapter 3 section 3.2.3), the modelling showed a wide variation in production costs, depending on the method of production. It ranged from £1.11 per kg using SMR technology through to £3.44 per kg for electrolysis. Considering this wide range in production costs it would appear that the method, and hence cost of production, is critical to making hydrogen economically viable.

In terms of environmental issues, not all pathways improve overall emissions compared to the diesel base case even with hydrogen powered fuel cell vehicles having “zero emissions” at the point of use. The additional road tanker journeys that may be required to deliver hydrogen compared with diesel would add to the overall emissions, but it is not hydrogen distribution, but hydrogen production which is the main concern. Hydrogen from the SMR process does reduce emissions according to Figure 8-15, but perhaps biomass has greater potential for production of hydrogen as shown in Figure 8-15 particularly ‘second generation’ bio-fuels. Hydrogen from electrolysis offers no environmental benefit compared to the conventional diesel reference case if a typical UK mix is used for electricity generation (although the planned de-carbonising of electricity generation would help). In essence, to make an environmental case, hydrogen needs to be produced from zero or very low carbon fuels. In effect this means renewable electricity or perhaps

using thermal energy from nuclear power stations. Carbon reduction technologies such as CCS have potential to reduce emissions but at some cost. CCS is considered by many researchers as critical for “emissions free” hydrogen produced from hydrocarbons. The modelling in this thesis has addressed the issues of cost to a limited extent. Equipment costs used in the modelling can perhaps be considered as a best estimate and will continue to be so until the technology matures and more full scale plants are built and operated. It is an area of interest to researchers at present that has increased over the course of this research. CCS would add cost to the delivered cost of hydrogen at a time when it is not cost competitive, making the case for a future hydrogen economy more difficult to justify. It would seem that CCS is at best an interim measure to reduce emissions from hydrocarbon sources and ultimately hydrogen needs to be produced from emissions free sources

The two main components of any hydrogen production system are the capital cost of equipment and energy costs. Most centralised production technologies are relatively mature and hence cost reductions are limited without a new technology breakthrough. In chapter 9, the cost of localised electrolysis units were evaluated and in particular the necessary cost reductions needed to make this pathway viable. Most hydrogen production units are of bespoke design, particularly the large scale process plants. Smaller factory assembled units offer good potential for cost reductions as fully assembled units can be delivered to site ready for connection to utilities as required. Although chapter 9 identified the need for significant cost reductions, this may be possible with new production line style manufacturing techniques, providing sufficient demand exists..

## **10.2 The cost of distribution**

Although distribution is not the largest component of cost or emissions, results in this thesis have shown that it is a significant proportion of the overall delivered cost of hydrogen. Furthermore, there are significant variations in the delivery cost depending on the pathway chosen.

### **10.2.1 Hydrogen pathways**

This research started out with a wide number of different supply chains, and focused on the eleven most viable but, when fully explored, some of these do not seem to be viable. Whilst centralised production is the cheapest method of producing hydrogen, the cost of distribution is significant. As there is no significant hydrogen supply and distribution networks in place in the UK to date, any reduction in the options would help to reduce the danger of selecting inappropriate pathways.



This research has shown that liquid hydrogen is unlikely to be a viable option within the UK. It uses significant amounts of energy in the liquefaction process (and hence additional cost). Although transported today in limited amounts, it is more difficult to transport than gaseous hydrogen, cannot realistically be transported by pipeline and, finally, is not easy to store on board vehicles. Perhaps if this type of modelling was specifically carried out on the CUTE London project, it would have shown that centralised production and transportation in liquid form should not have even been considered for a demonstration project.

This research has also shown that, for most demand and supply chain lengths, the optimum method of delivery is by pipeline in gaseous form. This does not necessarily agree with the modelling results by other researchers. One possible reason for this is the generic estimates of pipeline costs in this research and possibly other research work, another possibility is the simplistic approach to costs which were reviewed earlier in this thesis. It is likely that more detailed analysis for pipeline delivery is required, based on specific demands, supply chain lengths as well as terrain. This will be addressed further in section 10.5. The capital cost of pipeline installation is significant and should not be considered on a single case basis, but included for potential future networks. This is perhaps an area where distribution network modelling would be appropriate, to ensure that hydrogen pipelines are sized to allow for future take offs to new refuelling facilities in the adjacent areas. Doubling the diameter of a 2" pipeline increases the capacity by a factor of four. It would be possible to build in spare capacity with a very small cost increase.

This research suggests that minimising or eliminating the distribution and supply chain length is desirable. Perhaps an ideal solution would see hydrogen coming from localised production using feed stock such as natural gas or decarbonised electricity which would make a hydrogen distribution system unnecessary. However, there is a counteracting problem in that localised production is more expensive and would place additional demand on gas and electricity distribution networks. It is possible that for a large scale uptake of hydrogen powered vehicles, the current electricity and natural gas grids may not have sufficient capacity. This would affect BEVs to a similar extent.

In some respects, these conclusions are at variance with related work by other researchers. However, whilst each researcher has to some extent addressed the distribution system, it is often from a different perspective from that adopted in this thesis. In some cases the research modelled distribution networks, others considered generic supply chains without respect to terrain, delivery

speed etc. With limited data sources available, some common data has been used. For example, both this research model and the work by Yang and Ogden refer to Amos's 1998 paper, "The cost of storing and transporting Hydrogen" (Amos W, 1998). Another example of commonality is Dr Joan Ogden, who was a contributor to one paper (Yang C and Ogden J, 2006a) and also on some of the US DoE committees associated with hydrogen research in the US DoE hydrogen model (Milliken J, 2008). This does not however mean that results and conclusions are also duplicated.

It is clear from the modelling work in chapter 8 that even with the best of models, it is important to ensure key data such as capital costs, are as accurate as possible. It is also important, is to ensure that accurate energy data costs are included, as all the production processes are energy intensive. The model work in this research has sought to address in more detail where some of the variations in data can affect the supply chain, particularly when modelling issues such as pipelines and delivery speeds etc. This was identified as a weakness in some other studies. The ability to change a number of variables related to energy costs in the model such as energy mix, cost and emissions of individual methods of generation as well as other factors such as distribution costs, appear to be unique when compared to the research work by fellow researchers in this field. This has enabled a wide range of "what if" scenarios to be used in relation to both the cost and emissions of various pathways.

## **10.2.2 Hydrogen distribution networks**

Centralised production and distribution has generally been shown to be the most economical option to supply hydrogen for single bus fleets to a centralised fuel depot. There may be small exceptional circumstances within the UK where this is not the case. For example, the island of Unst, referred to in chapter 5, for a small hydrogen powered bus fleet of just a few vehicles. Here, the demand and supply chain length to the nearest hydrogen production facility would not make centralised production economically viable. However for most mainland urban situations it is reasonable to assume that centralised production is preferable. It therefore follows that if / when more bus fleets are converted to hydrogen, some form of distribution network will be needed.

The evidence in this research demonstrates that gaseous hydrogen by road tanker does not appear to be the most economical distribution method when compared with pipelines, but perhaps it is still worth considering what a gaseous hydrogen road tanker distribution network may look like. Distribution networks tend to match demand to supply points and choose locations accordingly. For two main reasons it may be that such networks are merely multiple single point distribution



systems. Firstly, the low carrying capacity of gaseous hydrogen tankers, mean that the distribution network is likely to be radial. In other words, one tanker delivers a full load to one depot (one tanker equates to only 1440km of bus travel based according to CUTE). Secondly, the location of a centralised distribution facility may not be able to be sited to suit the end users. For example if CCS technology is used and a feed stock that does not have a distribution network in the UK, the overriding factor may not be the distance to the end users but the distance to a suitable carbon dioxide storage place or feedstock. In these situations, the single point model used in this thesis could be used to model distribution networks on the basis that normal network models to these specific limited scenarios are less applicable, as different feed-stocks and geographies will not cope with the one size fits all solution.

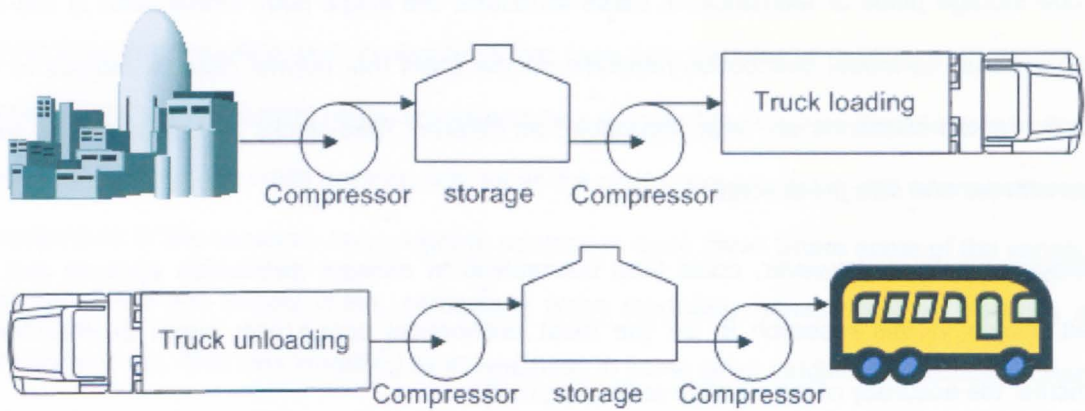
Hydrogen pipelines, however, could lend themselves to network distribution systems and have been shown in this research to be the most economical option with some qualifications (in particular the accuracy of the pipeline estimating tool).

It would be reasonable to assume that pipeline estimates used in research for modelling purposes, whether single point, as in this research, or distribution networks used by others are likely to be fairly approximate. Both types of model are likely to be generic rather than specific, as the latter would require detailed design of routes and terrain. The calculation method used in this research took into account a number of different types of crossings for roads and rivers for varying lengths of supply, which although estimated, has provided a reasonably accurate reflection of a typical pipeline system even if generic. Whilst it can only consider one pipeline at a time it could be used to model individual costs of each branch of any distribution networks and perhaps input to the distribution network models improving accuracy of cost estimates.

At this stage it seems unlikely that distribution networks will start to evolve in the UK in the near future on the basis of hydrogen demand. Recently, there has been significant replacement of old natural gas pipeline systems in the London and the South East. One possibility for a future hydrogen network might be to install hydrogen pipelines alongside the natural gas pipelines for future use. Although this would add some cost in terms of additional piping materials, it would avoid the major costs of excavation and reinstatement of the terrain. It would however need to be part of an overall future energy policy by government and is not considered further here.

### 10.3 The cost and emissions associated with storage

One conclusion from the modelling in chapter 8 and the technology developments in chapter 9, showed that the cost of hydrogen storage was not insignificant and perhaps this was an area that should be prioritised for further work. Additionally, the process of loading / unloading and loading again is more complicated, time consuming, energy intensive and hence expensive when compared to a simple liquid such as diesel.



**Figure 10-1 Hydrogen delivery chain (gaseous road tanker)**

From Figure 10-1, it can be seen that up to four compression stages are required, all requiring energy which would add to the total emissions due to delivery and also, in the case of loading and unloading of the delivery tanker, increasing delivery times and hence cost.

. Any new developments in terms of storage materials and hence increased pressures could easily be evaluated using the research model, providing the cost and carrying capacity of any new tankers or storage tanks were known. It is important for hydrogen distribution system researchers to monitor the work of material researchers involved in hydrogen supply and distribution systems as it is possible that a technology breakthrough may occur in either battery storage densities or perhaps even solid state hydrogen storage.

Solid state hydrogen storage is already technically feasible, as reported earlier, with first generation metal hydride cylinders storing small amounts of hydrogen. Further research is required in this field relative to hydrogen supply and distribution systems. There are several possibilities for future solid state hydrogen storage systems:-

1. A gaseous hydrogen distribution system which is loaded to on board vehicle solid state hydrogen storage systems.
2. Transporting hydrogen using large solid state hydrogen storage tankers, then loading on board to either gaseous or solid state hydrogen storage tanks.



3. Using centrally filled, replaceable solid state hydrogen storage tanks which are then fitted as replacement units in vehicles (referred to earlier in chapter 3, as the Calor gas scenario).

The first scenario does not affect the current distribution system reviewed as part of this research. The second scenario is perhaps worthy of further modelling work, and can easily be modelled as reported earlier providing the carrying capacity and loading / unloading rates of the new type of tankers are known. However it is unlikely that solid state hydrogen will be transported by tankers for the reasons given, i.e.: high cost. The third scenario appears to be the most likely. In this scenario, a simple distribution system is needed as for any other industrial goods. It does, however, require development of vehicles suitable for “tank exchange”. Although this research model is not suitable to analyse this scenario, a relatively simple model is needed and could easily be developed once realistic costs and reliability data is available for metal hydride storage cylinders for example.

## **10.4 The competition between hydrogen FCVs and BEVs**

The resurgent interest in battery powered electric vehicles and the technology improvements in this area show that hydrogen has not yet won the race as a future transport fuel. Indeed, it is possible that a better fuel supply system for BEVs may give them an advantage over FCVs, despite their limited range, battery costs and long re-charging times. Many developed nations are rolling out programmes for an extensive network of public charging points. In September 2009 the Energy Technologies Institute announce an £11 million plan to help support nine cities across the UK develop a national network of charging points (ETI, 2009). In the case of London, there is a plan to roll out 25,000 charging points, although it is not clear from the press release how much of the funding is allocated to this specific plan. This would give BEVs a significant advantage over FCVs in terms of a re-fuelling infrastructure. There is also a significant amount of work currently being carried out to develop faster charging times for BEVs. Epyon, a company formed out of research activities at Delft University in the Netherlands is one such company working on these technical challenges. Although their high speed charger is not as fast as conventional fuelling of hydrocarbon vehicles, they claim charging times for a car in the range of 15 to 30 minutes (Epyon, 2009); albeit with limitations mentioned earlier in section 2.1.



An independent report on the future of the automotive industry in the UK anticipates initial widespread uptake of BEVs with FCVs following on later, although it does not seem to draw conclusions regarding which technology will be dominant in the long term (NAIGT, 2009).

At the start of this research (2002), BMW launched their 750H hydrogen car at a presentation in London attended by political leaders, technologists and the media, extolling the virtues of a hydrogen future. Yet to date, the only hydrogen vehicles to have been in public use in London have been the CUTE buses. Interestingly, the BMW 750H used an internal combustion engine and stored hydrogen in liquid form, compared to the CUTE buses which used electric motors, fuel cells and stored the hydrogen in gaseous form. It is a good example of the difficulties of predicting the future in terms of both timescale (in this case just a few years) and technology.

During the period of this research, much of the media attention has tended to focus on the BEV. Although this research focuses on technology, the issue of public perception and consequently media interest cannot be ignored. The following, although not from credible academic sources, illustrate well the situation. Two examples can be drawn from the state of California. Ken Bensinger, a journalist on the Los Angeles Times has written several articles on this subject, two headlines of relevance were "It's a bumpy ride on the hydrogen highway" (Bensinger K, 2008a), whereby it is reported that not only are hydrogen filling stations not opening at the forecast rate, several hydrogen stations are actually closing. Another article titled "Road for electric cars makers full of potholes" (Bensinger K, 2008b), suggest that there are both financial and technical obstacles yet to be overcome with electric vehicles. Citing the Tesla (reviewed earlier) as being delayed several months due to technical problems, one of which was the need to solve transmission problems which reduced acceleration by 40% and that they plan to make only 1,000 vehicles at a price of \$100,000 each. In the UK, a recent episode of the BBC *Top Gear* (Top Gear, 2009) also visited California to look at hydrogen cars when it compared a Lotus Elise powered by a conventional petrol ICE, a Tesla battery powered electric vehicle and a Honda FCX Clarity hydrogen powered FCV.

The initial comparison between the Lotus ICE and the Tesla on a test track reported favourably on the Tesla, with enhanced performance in terms of acceleration and cheaper refuelling (£3.50) using off-peak electricity, compared with £40 for the Lotus ICE, based on similar claimed driving ranges. It then went on to list some of the disadvantages of the Tesla:-

1. Unreliability and handling due to significant weight attributed to the 500kg batteries.

2. Reduced range from the claimed 200 miles down to 55 miles when driven aggressively.
3. The Tesla was approximately three times the cost of a conventional Lotus.
4. 16 hours charging time with a conventional 13 amp power supply or 600 hours charging time using a typical small wind turbine.
5. If grid electricity is used, the source is still largely hydrocarbon based.

This is consistent with industry and academic research on vehicle technology, particularly with respect to the cost, charging rates and the electricity source being produced largely from hydrocarbons. The programme then went on to extol the virtues of the hydrogen powered Honda, claiming that appeared to be fundamentally the same as driving a conventional Honda vehicle in terms of range and performance. However, it did not address costs but claimed that refuelling of the gaseous hydrogen took no more than two to three minutes, with a range of 240 miles. It also claimed that hydrogen, supplied from a public Shell filling station, cost approximately the same as petrol. It pointed out that in a world short of oil, hydrogen may be the future and, whilst it may be difficult to produce, the technology was available.

Clearly this is a somewhat biased and over simplification of the academic issues addressed in this research, but it is interesting to note the future was seen as a choice between electric powered battery vehicles and hydrogen powered fuel cell vehicles. Whilst there were technology and cost issues associated with both vehicles, it was the fuel storage and loading systems which seemed to be the obstacle for the battery powered electric vehicle, with hydrogen being portrayed as the 'obvious' choice for the future. However, the programme had some fundamental flaws. This research project suggests that the programme's assertion that the cost of hydrogen would be "about the same as petrol", is not correct in either the UK or the USA using current assumptions, and the programme glossed over other important difficulties.

If one accepts that the future motive power for vehicles is likely to be an electric motor rather than an internal combustion engine, the two main alternatives for on-board energy storage seem to be the electric battery or hydrogen. In which case, the study of hydrogen storage and distribution systems will be relevant given the cost variations discussed earlier in this chapter. Even if hydrogen fuelled internal combustion engines were to see widespread use, rather than fuel cell vehicles, a hydrogen supply and distribution systems would still be needed.

A future transition from the current diesel base case may take place for both private and fleet vehicles. For the reasons given at the beginning of this thesis, fleet vehicles may well be particularly suitable for a niche hydrogen vehicle market and the choice of a single point model for

such a niche system is particularly appropriate. Another niche system, such as BEVs may develop for private vehicles (e.g. an electric city car club). To some extent it would help further research if this was the case as it would simplify the modelling into single point, or small scale distribution networks for fleet vehicles such as buses, and separate, city wide distribution systems, for BEVs. One area of research which may be important is to investigate how such niche systems could co-exist. It may be that future modelling addresses the whole transport system rather than just component parts.

Figure 10-2 shows one possible transition route. It starts with current technologies such as conventional petrol or diesel for both private and fleet vehicles, considering diesel hybrids as the next stage. Beyond that, it is possible that the two routes will diverge. Private vehicles may move to on board energy storage using batteries due to space limitation requirements of gaseous hydrogen tanks. Fleet vehicles are less limited by space restrictions and hence could store energy on board in the form of hydrogen. Beyond that is more difficult to predict and depends largely on future developments of hydrogen storage systems compared to battery technology and charging rates. Technically, either of the two transition routes could be interchanged as the fleet vehicle transition could be applied to private vehicles, but if hydrogen is to be used for private vehicles, a fully developed hydrogen supply and distribution system is needed, or alternative localised production at reasonable costs. There are other possibilities, one of which will be discussed next in recommendations for further research.

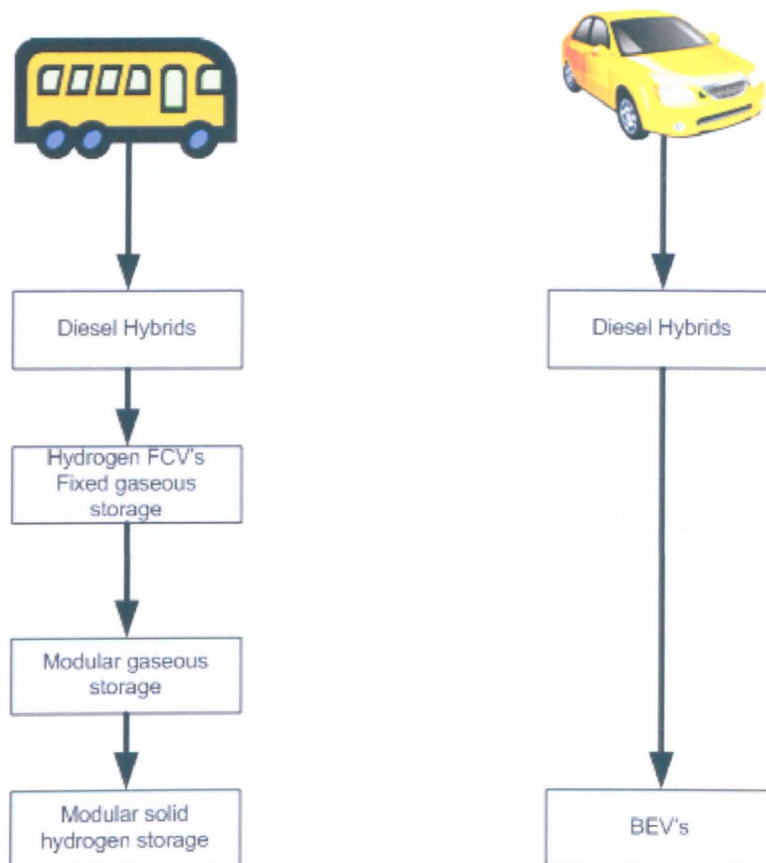


Figure 10-2 Possible transition stages

## 10.5 Recommendations for further research

Changing a complete fuelling system and infrastructure is no small task and unlikely to be achieved as part of one piece of research. In fact it has been quoted that *"replacing an entire technologically advanced energy system with something else is a huge undertaking, spanning decades. It is like trying to change the course of super tanker with kayak paddles"* – David Hart (Hoffmann P, 2002, p14).

The original aims of this research, its goals and outcomes have been discussed earlier in this chapter, and it now appropriate to consider the direction any future research may take. The first and perhaps main area is to develop the modelling tool used in this thesis. Particularly if a simple decision tool can be developed to aid organisations who would like to consider implementing a hydrogen bus transport scheme but perhaps have no clear solution as to how to supply hydrogen for these vehicles.

This research has shown that hydrogen may need some help to become competitive in terms of costs when compared with existing systems, eg: through energy price management by taxation.

Although discussed briefly in this research, the topic has been outside the scope of this research. It may be an area of further research that could be crucial to making hydrogen competitive in the short term.

Another area for future consideration is the development of vehicle types. This research started out by comparing hydrogen FCVs against a base diesel reference case. Recently the competition appears to be more focussed on BEVs. Perhaps another useful area of research is to investigate how future systems could evolve so that they may have the flexibility to change technologies with minimum impact on any future energy / fuel supply system.

### **10.5.1 Development of the model used in this research**

Clearly it is important to accurately model specific cases. This was also the conclusion in Yang's work when attempting to determine the lowest cost hydrogen delivery mode, when it was proposed to focus on real cities in their network distribution model, (Yang C and Ogden J, 2006a, p285). The model in this research can be applied for specific road transport cases, but would need to use a more elaborate model for pipeline estimating to achieve the required accuracy. The Penspen pipeline estimating tool used in the model could be incorporated into this research model. Whilst this would improve accuracy, it would require a significantly greater amount of input and still only achieve an accuracy of +/- 25%, as reported earlier. A more useful development may be to modify the research model to give a cost range for pipeline costs, quoting an upper limit, above which pipelines are not cost effective, a mid range whereby more detailed analysis is required, and a lower limit below which pipelines are clearly cost effective. If the results show further analysis is required, the pipeline estimating model can be used.

At present, the model does not consider future supply and distribution systems such as solid modular hydrogen storage either in gaseous or solid form as suggested in the transition diagram but in these scenarios the distribution system becomes more conventional in that hydrogen is transported as a "package".

### **10.5.2 Decision making using the research model**

The model developed during the course of this research was necessary to carry out the quantitative analysis of a number of hydrogen pathways. Although specifically developed as a tool for this research, it could be used for calculating the optimum hydrogen supply and delivery systems for a wide variety of demand and supply chain distances. Before that stage, it may be useful to have a means of choosing when / if a hydrogen supply and distribution system may be



desirable. One method of achieving this is to use a decision tree chart, which if suitably calibrated to this research model, may help with the decision process of comparing a hydrogen system compared with a diesel base reference case. A typical chart is shown below in Figure 10-3.

It should be stressed that this is generic design of chart and the values used in the chart are indicative only. For example “demand>100 kg / day”, this figure would need to be calculated as it is currently outside the boundaries of the model. To a large extent, the decision chart is self explanatory, although it introduces a few new key elements to the model in the decision making process:-

- 1 A low demand niche / demonstration project scenario where simple delivery by gaseous hydrogen road tanker would be the optimum route.
- 2 Energy taxation required to aid the cost competitiveness of hydrogen.
- 3 An emissions reduction loop and the associated cost impact is assessed.
- 4 Detailed pipeline cost evaluation depending on the range of results.

The research model can be used to quantify the costs and equally, if required, the emissions that would be needed to “calibrate” the chart in terms of the yes / no decisions.

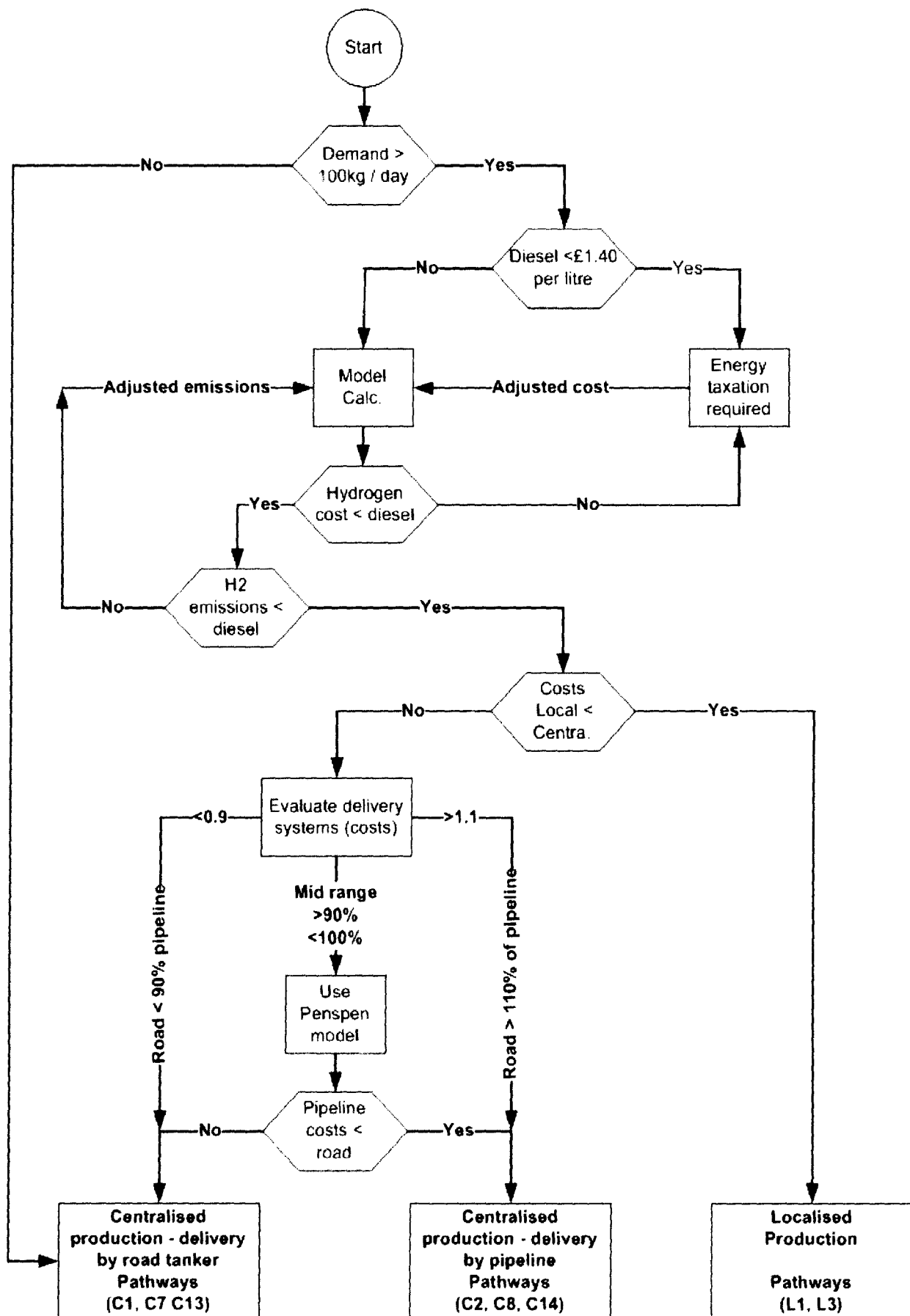


Figure 10-3 Hydrogen decision flow chart

### **10.5.3 Energy price management by taxation**

Energy for hydrogen production is one of the main cost components in evaluating pathways and hence the model used in this research was developed to allow maximum flexibility, with careful consideration to ensure that all energy costs were calculated nett of tax. It also allowed for variation in electricity mixes to consider emissions. It has enabled a fairly detailed analysis of costs based on both current figures as well as potentially viable cost reductions required to make hydrogen competitive with diesel for fleet vehicles.

The technology development work in chapter 9 has shown potential for hydrogen pathways to become competitive with diesel, at a cost in the region of £1.50 per litre. With diesel currently at £1.10 (post-tax) per litre, and UK prices amongst some of the most expensive in Europe, the argument for conversion to a hydrogen economy on cost alone has not been substantiated. It would appear that energy price management by taxation may be necessary to achieve a significant uptake in hydrogen powered vehicles.

This is a complex and complicated area, as there are a number of ways in which this could be achieved. The most obvious being a tax on diesel and other fuels to match it to the cost of hydrogen. However there are other options such as the subsidy of renewable electricity to enable a “zero emissions” electrolysis hydrogen system to develop. This may involve taxation on more than one energy source, a general hydrocarbon tax would also logically affect hydrogen production by SMR as it uses natural gas as a feedstock.

Although not designed to be an economic tool to compare energy costs, the research model is capable of carrying out analysis with reasonable accuracy of the required cost of the different forms of energy, excluding taxation and is an area of interest to the author, as potential further research.

### **10.5.4 BEV / hydrogen hybrid vehicles**

One area of interest and potential for future research is the use of hybrid vehicles, whether for fleet or private vehicles. The generally accepted definition of hybrid is a combination of a hydrocarbon fuel powered ICE and an electric motor powered by an on board battery. This is a very limited definition and it is possible that future vehicles may be powered a variety of hybrid mixtures due to current limitations of energy storage, charging rates and, in the case of hydrogen, no supply and distribution system.

One possible future vehicle is the “hydrogen hybrid”, whereby BEVs with on board electric batteries are used for energy storage but supplemented by a back up hydrogen system consisting of a gaseous hydrogen (and possibility later solid state hydrogen) storage system to overcome current technical limitations of batteries in terms of range and charging rates. Such vehicles would effectively require two fuel distribution systems (electricity and hydrogen) and fuel cells on board. This may appear to complicate the issue but an electricity distribution system is already in place and the hydrogen system required would be greatly simplified. Research into such systems is outside the scope of this thesis but the limited hydrogen infrastructure required to support such a vehicle would suggest that it is an area worthy of further research work.

Although not directly related to hydrogen hybrid vehicles, the Royal Mail have been considering the issue and in a presentation by Dr. Martin Blake in 2009, introduced the idea of vehicle types matching requirements (Blake M, 2010). For short range local delivery BEVs would be used and longer range deliveries would be carried out using diesel hybrids. In the presentation, Blake proposes a gradual transition to hydrogen fuel cell vehicles by the development of a hydrogen highway which links existing clusters, from London to Aberdeen in a Northerly direction and London to Wales in a Westerly direction. Interestingly, it does not propose development of a hydrogen highway to the South of London or to the South West of England. The development of hydrogen hybrids may be able to replace the diesel hybrids and also reduce the scale of such a hydrogen highway with fuelling points only needed at the limit of the range of the vehicles.

## **10.6 Professional development**

This PhD research started as a result of interest generated by researchers and technologists in the use of hydrogen powered fuel cell vehicles. At that time I was employed as an engineer in the hydrogen production industry. Based on my knowledge and experience it appeared to me that any “new” hydrogen economy might be restricted by the lack of an established infrastructure and distribution system. Although reasonably well equipped to appreciate the technical difficulties and challenges with the hypothesis of this thesis, it soon became clear that additional skills were required to carry out academic research and analysis.

Upon reflection, it is clear now that this research degree has involved a number of separate learning processes which, although at the time seem to be separate and independent activities, were to combine to enable the research to be carried out to write this thesis.

Initially, this involved attendance at numerous presentations and seminars. Apart from providing useful background information, it also helped identify key academic researchers working in the same field and proved to be a useful networking exercise. At that time there were relatively few researchers involved in this field. Early work involved a review of current demonstration projects in progress, which included visits and interviews with key personnel involved. This provided some of the background material for chapter 5.

The next stage involved the writing of position papers to investigate the current situation. When looking back at the earlier papers, compared with this thesis, it is clear where skills have been developed. Parts of the content of these papers were used in chapters 2, 3 and 4, albeit with significant editing required. Both the networking skills and the position paper learning experiences proved to be useful during the literature review phase of this thesis.

Having completed these phases of the research learning process, basic modelling skills were developed using an Excel based spreadsheet program. This involved the use of “look-up” tables, Visual Basic programming techniques and graphical presentation of modelling results. Although this thesis is not entirely based on modelling, it has been necessary, to provide results of various scenarios and technology developments which were used in chapter 8 and 9.

One of the more useful skills development acquired during this research project was the need for, and use of different types of writing skills. As an engineer I was familiar with the techniques for writing specifications and technical reports, but this style was quite limited and not always relevant to research work. As an exercise in journalistic style writing skills I wrote an article titled “Tilting at hydrogen tanks in Hornchurch” which was published in *Renew*, an on line publication by the Network for Alternative Technology and Technology Assessment (NATTA) (Berridge C, 2004). Academic writing skills were practiced in two papers for UTSG conferences (Berridge C, 2008) and (Berridge C, 2009). In addition, there were numerous opportunities to work on presentational skills. This varied from small scale informal meetings at establishments such as De Montfort University, The Transport Research Laboratory at Wokingham and the Open University at Walton Hall to the larger audiences of the UTSG conferences. Each of these required a different style of presentation adapted to the target audience.

Although this thesis is based on a specific hydrogen future scenario, the experience gained in academic research has been useful to carry out analysis in a number of areas related to my work in the oil and gas industry. This includes technical investigations and reports as well as the need to



report these findings to senior managers at presentations in a form that explains the issue simply but clearly highlights the findings and conclusions.

Perhaps the best definition of the difference between a taught degree and a research degree is that with the former, one tends to believe and accept any information received in written form. With the latter, one tends to be cautious of any information unless it can be corroborated in some way or another, usually by the work of other researchers. An example of this was in the early model results which showed discrepancies between my results and other researchers. As an undergraduate I would have tended to accept the results of other researchers, on the assumption that my model was wrong. As a research student, I carried out further detailed analysis and found that in some cases my model was correct and others possibly wrong or at least a result of an alternative research outlook.

# Appendices

## Appendix 1 – Safety issues associated with hydrogen as a vehicle fuel (Cadwallader L and Herring J, 1999)

Hazard type	GASEOUS HYDROGEN	LIQUID HYDROGEN
Physical properties leading to safety concerns	<ul style="list-style-type: none"><li>• Lighter than air</li><li>• Highly diffusive</li><li>• Flow induced static discharge generation</li><li>• Low viscosity (leaks easily)</li><li>• Odourless and colourless</li></ul>	<ul style="list-style-type: none"><li>• Boil off gas quickly warms and then is lighter than air</li><li>• Boil off gas is highly diffusive</li><li>• Flow induced static discharge generation</li><li>• Boil off vent rate from storage tanks / fuel tanks is typical to maintain cold temperature in tank</li><li>• Rapid phase transition from liquid to gas can cause explosions</li><li>• Liquid quickly contaminates itself by condensing gases from air contact</li><li>• Odourless and colourless, cannot easily be odorised as odorants will freeze out at cryogenic temperatures</li></ul>
Pressure	<ul style="list-style-type: none"><li>• High pressure storage (2000 psig or more) can result in pressure rupture, flying debris</li><li>• Pipe whip concern with leak events</li><li>• Oxygen displacement in confined spaces</li><li>• Gas jet impingement damage is possible</li><li>• Gas jet impingement on personnel is also a hazard, high pressure can cut bare skin</li></ul>	<ul style="list-style-type: none"><li>• Storage under modest pressure to suppress boiling (perhaps 200 psig)</li></ul>
Chemical	<ul style="list-style-type: none"><li>• Flammable with non luminous flame, no toxic combustion products</li><li>• Explosive 4% to 75% by volume. Can deflagrate (typically only a modest overpressure, ~ a few psi in open areas. Can also detonate (high overpressure shockwave, ~ several atmospheres.</li><li>• Low ignition energy, 0.02 mJ to 1 mJ spark to ignite a deflagration</li><li>• Modest auto ignition temperature, 574 deg C</li></ul>	<ul style="list-style-type: none"><li>• Evolved gas is cold, otherwise same concerns as gaseous hydrogen</li></ul>
Temperature	<ul style="list-style-type: none"><li>• Could be stored at room temperature, not an issue</li></ul>	<ul style="list-style-type: none"><li>• Cryogenic burns, especially eyes</li><li>• Lung damage by cold vapour inhalation</li><li>• Possible hypothermia working near these systems</li><li>• Condensation of air near LH<sub>2</sub> systems if insulation allows heat leak paths, easy heat transfer</li></ul>
Material issues	<ul style="list-style-type: none"><li>• Embrittlement of metal</li><li>• Embrittlement of plastics</li></ul>	<ul style="list-style-type: none"><li>• Embrittlement of metal</li><li>• Mechanical stresses generated by thermal contraction</li><li>• Mild steels susceptible to cracking at cryogenic temperatures</li><li>• Materials have low specific heats at cryogenic temperatures, easy heat transfer</li></ul>
Toxicological	<ul style="list-style-type: none"><li>• Asphyxiation in confined spaces</li><li>• No other toxic concerns</li></ul>	<ul style="list-style-type: none"><li>• Asphyxiation in confined spaces</li><li>• Frostbite from acute exposure</li><li>• Hypothermia possible from long exposure</li><li>• No other toxic concerns</li></ul>

## Appendix 2 - US DoE Production case study details

Case Study file name	01D_Current_Central_Hydrogen_Production_from_Coal_without_CO2_Sequestration_version_2.0.1	03D_Current_Central_Hydrogen_Production_from_Coal_with_CO2_Sequestration_version_2.0.1	01D_Current_Central_Hydrogen_Production_from_Grid_Electrolysis_version_2.0.1	01D_Current_Central_Hydrogen_Production_from_Natural_Gas_without_CO2_Sequestration_version_2.0.1	03D_Current_Central_Hydrogen_Production_from_Natural_Gas_with_CO2_Sequestration_version_2.0.1	01D_Current_Central_Hydrogen_Production_via_Biomass_Gasification_version_2.0.1	01D_Current_Forecourt_Hydrogen_Production_from_Ethanol_(1,500_kg_per_day)_version_2.0.1	01D_Current_Forecourt_Hydrogen_Production_from_Grid_Electrolysis_(1,500_kg_per_day)_version_2.0.1	01D_Current_Forecourt_Hydrogen_Production_from_Natural_Gas_(1,500_kg_per_day)_version_2.0.1
Title:	Current (2005) Hydrogen from Coal without CO2 Capture and Sequestration	Current (2005) Hydrogen from Coal with CO2 Capture and Sequestration	Current (2005) Hydrogen Production from Central Grid Electrolysis	Current (2005) Hydrogen from Natural Gas without CO2 Capture and Sequestration	Current (2005) Hydrogen from SMR Natural Gas with CO2 Capture and Sequestration	Current (2005) Hydrogen from Biomass via Gasification and Catalytic Steam Reforming	Current (2005) Ethanol Steam Reformer (SR) at Forecourt 1500kg/day	Current (2005) Hydrogen Production from Distributed Grid Electrolysis	Current (2005) Steam Methane Reformer (SMR) at Forecourt 1500kg/day
Authors:	Mike Rutkowski	Mike Rutkowski	Todd Ramsden	US DOE/NETL MD Rutkowski	US DOE/NETL	D. M. Steward	Brian D. James, Directed Technologies Inc.	Todd Ramsden	Brian D. James, Directed Technologies Inc.
Contact:	Darlene Steward	Darlene Steward	Todd Ramsden	Darlene Steward	Darlene Steward	D. M. Steward	Brian D. James	Todd Ramsden	Brian D. James
Contact phone:	303 275 3837	303 275 3837	(303) 275-3704	303 275 3837	303 275 3837	303 275 3837	(703) 243-3383	(303) 275-3704	(703) 243-3383
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Organization:	National Renewable Energy Laboratory (NREL)	National Renewable Energy Laboratory (NREL)	National Renewable Energy Laboratory (NREL)	National Renewable Energy Laboratory (NREL)	National Renewable Energy Laboratory (NREL)	National Renewable Energy Laboratory	Directed Technologies Inc.	National Renewable Energy Laboratory (NREL)	Directed Technologies Inc.
Date:	28-May-08	27-May-08	28-May-08	28-May-08	28-May-08	28-May-08	27-May-08	27-May-08	23-May-08
Web Site:	<a href="http://www.nrel.doe.gov">www.nrel.doe.gov</a>	<a href="http://www.nrel.gov">www.nrel.gov</a>		<a href="http://www.netl.doe.gov">www.netl.doe.gov</a>	<a href="http://www.nrel.gov">www.nrel.gov</a>	<a href="http://www.nrel.gov">www.nrel.gov</a>			
Plant Design Capacity (kg/day):	283,830	307,673	52,300	379,387	379,387	52,300	1500	52,300	1500
Start-up Year:	2005	2005	2005	2005	2005	2005	2005	2005	2005
Primary Product Feedstock Source:	Electric Utility Steam Coal	Electric Utility Steam Coal	Process Water	Industrial Natural Gas	Industrial Natural Gas	Farmed woody biomass	Ethanol (Neat)	Process Water	Industrial Natural Gas
Secondary Feedstock Source:	None	None	none	None	None	none	None	none	None
Process Energy Source:	Standard fossil energy sources	Standard fossil energy sources	Grid Electricity (Industrial)	Standard fossil energy sources	Standard fossil energy sources	Internally generated steam and electricity; Industrial electricity and Commercial Natural Gas	Commercial Electricity	Grid Electricity (Industrial)	Commercial Electricity
Conversion Technology:	Gasifier, quench, sour shift, AGR, PSA	Gasifier, quench, sour shift, AGR, PSA, CO2 Compression	Alkaline Electrolysis	Steam reformer, quench, shift, PSA	Steam reformer, quench, shift, PSA, CO2 Removal and Compression	Battelle Columbus Laboratory Indirectly-Heated Gasifier	SR of Ethanol/PSA Purification	Alkaline Electrolysis	SMR of Natural Gas/PSA Purification
Primary By-Product:	Electric Power, Sulfuric Acid	Electric Power, Sulfuric Acid	none	Steam export	none	none	None	none	None
Secondary By-Product:	None	CO2	none	No	Yes	none	None	none	None
Based on Number of Plants Installed per Year (per manufacturer):	Nth	Nth		None	nth	Nth plant	nth plant (~500 units/yr)	nth plant (~500 units/yr)	nth plant (~500 units/yr)
H2 Onsite Storage Type	N/A	N/A	none	N/A	N/A	none	6,250 psia H2 Compressed Gas Storage	6,250 psia H2 Compressed Gas Storage	6,250 psia H2 Compressed Gas Storage
Assumed plant location:	Mid USA	Mid USA	USA	Mid USA	Mid USA	USA, average		USA	



### Appendix 3 - US DoE Production case study summary of results<sup>39</sup>

Case Study file name	method	Plant capacity (kg/hr)	Cap cost (installed)	Energy data				Cost data \$ / kg of hydrogen										Emissions data			Notes
				Electricity		Gas												KG CO <sub>2</sub> e / kg H <sub>2</sub>			
				Cost \$ / kWhr	Amount req'd kWhr / kg H <sub>2</sub>	Cost \$ / Nm <sup>3</sup>	Amount req'd Nm <sup>3</sup> / kg H <sub>2</sub>	Capital Costs	Decommissioning Costs	Fixed O&M	Feedstock Costs	Other Raw Material Costs	Byproduct Credits	Other Variable Costs (including utilities)	Total	Compression storage and dispensing costs	Upstream	Process	Well to tank		
01D_Current_Central_Hydrogen_Production_from_Coal_without_CO2_Sequestration_version_2.0.1	1	11,826	\$312,811,396	-0.030	3.175			\$0.88	\$0.00	\$0.26	\$0.31	\$0.00	-\$0.10	\$0.04	\$1.39	not inc.	0.00	21.42	21.42	Pittsburgh No.7 Coal 2005 prices, Costs \$0.037 / kg, required = 8.508 kg /kg H <sub>2</sub>	
03D_Current_Central_Hydrogen_Production_from_Coal_with_CO2_Sequestration_version_2.0.1	2	12,820	\$390,919,248					\$1.27	\$0.00	\$0.30	\$0.29	\$0.00	\$0.00	\$0.17	\$2.03	not inc.	1.34	1.98	3.32	Pittsburgh No.8 Coal 2005 prices, Costs \$0.037 / kg, required = 7.859 kg /kg H <sub>2</sub>	
01D_Current_Central_Hydrogen_Production_from_Grid_Electrolysis_version_2.0.1	3	2,179	\$94,365,000	0.055	53.440			\$1.16	\$0.00	\$0.32	\$2.94	\$0.02	\$0.00	\$0.03	\$4.48	not inc.	41.53	0.00	41.53		
01D_Current_Central_Hydrogen_Production_from_Natural_Gas_without_CO2_Sequestration_version_2.0.1	4	15,807	\$134,843,693	0.055	0.569	0.243	4.501	\$0.25	\$0.00	\$0.06	\$1.13	\$0.00	\$0.00	\$0.07	\$1.50	not inc.	1.72	9.28	11.00		
03D_Current_Central_Hydrogen_Production_from_Natural_Gas_with_CO2_Sequestration_version_2.0.1	5	15,807	\$156,185,457	0.055	1.406	0.243	4.489	\$0.45	\$0.00	\$0.09	\$1.17	\$0.00	\$0.00	\$0.15	\$1.86	not inc.	2.37	0.93	3.30	Carbon sequestration at 9.28kg CO <sub>2</sub> / kg H <sub>2</sub> based on 90% recovery	
01D_Current_Central_Hydrogen_Production_via_Biomass_Gasification_version_2.0.1	6	6,468	\$111,879,925	0.055	1.600	0.340	0.170	\$0.53	\$0.00	\$0.21	\$0.69	\$0.15	\$0.00	\$0.19	\$1.77	not inc.	1.29	24.92	26.21	Farmed woody biomass forecast 2012 prices Cost = \$0.042 / kg, Req'd = 12.84 kg / kg H <sub>2</sub>	
01D_Current_Forecourt_Hydrogen_Production_from_Ethanol(1,500_kg_per_day)_version_2.0.1	7	63	\$1,067,051	0.082	0.490			\$0.53	\$0.00	\$0.18	\$3.15	\$0.00	\$0.00	\$0.05	\$3.10	\$1.88	1.91	12.53	14.44	Ethanol costs 2005 prices, cost = \$ 1.07 / gallon, req'd = 2.91 gallons / kg H <sub>2</sub>	
01D_Current_Forecourt_Hydrogen_Production_from_Grid_Electrolysis(1,500_kg_per_day)_version_2.0.1	8	63	\$2,479,950	0.055	53.440			\$0.98	\$0.00	\$0.40	\$2.94	\$0.04	\$0.00	\$0.03	\$4.39	\$1.82	42.88	0.00	42.88		
01D_Current_Forecourt_Hydrogen_Production_from_Natural_Gas(1,500_kg_per_day)_version_2.0.1	9	63	\$956,810	0.082	1.100	0.243	4.488	\$0.45	\$0.00	\$0.16	\$1.18	\$0.00	\$0.00	\$0.10	\$1.89	\$1.88	3.67	9.26	12.93		

<sup>39</sup> The cost differentials for gas and electricity are based on industrial or commercial costs, with industrial costs being the lower figure. The authors of these case studies have presumably selected these on the basis of amount of energy used.

# Appendix 4 – Chapter 7 model detailed instructions

The purpose of this Appendix is to act as an instruction manual for the user of the model and is intended to act as a stand alone guide. Consequently, some of the descriptions and comments in chapter 7 may be duplicated here.

## 1.1 Cover sheet and notes work sheets

This comprises of two sheets:-

- A cover sheet – with basic user instructions and revision boxes for record of formal issue
- A notes sheet – which explains background data such as heating values of hydrogen. This data already exists elsewhere in this research, but it is included to help the user when the model is being used as a stand alone calculation tool.

## 1.2 User Interface worksheet

This worksheet is to enable the basic level user to input variables for use on other spreadsheet in the model. Apart from some basic functions, such as summation of columns to ensure that figures add up, there are no other calculations that need further explanation in this worksheet.

USER INTERFACE SHEET
User input cell - can be modified to any value
Recommend practical value for user guidance - located adjacent to user input cell
Cell which is populated using selection buttons.

Figure App 4–1 Key to cell colour codes on user interface sheet

- The blue cells are for user inputs, and whilst there are no physical limitations to the values which can be inputted into the model, there are practical limits.
- The yellow cells are intended as a guide to the user and in some cases advise the practical limits. These contain typical values, or in some cases; ranges of values to guide the basic level user. These cells also include embedded comments, to advise of limitations, or reference the source of data.
- The purple cells merely indicate that they are changed by the select buttons. It is important to note that this is a manual action, which requires updating each time a user input variable is changed.

### 1.2.1 Fleet vehicle data



Fleet vehicle size data				
No. of Buses			min 10	100
Operating hours per day		hours	7	12
Average speed		km / hr	18	20
No. of operating days / year		days	360	360

**Figure App 4–2 Fleet vehicle size data**

- ❖ The red triangles in the corners indicate that there is a comment in that cell. To view the comment in the spreadsheet, the user should hold the mouse pointer over that cell in the model.
- ❖ The fleet vehicle size data must reach a minimum demand of 20kg / hr to ensure that the model functions correctly.

This section is largely self explanatory, it enables the user to define the basic size of the vehicle fleet, bearing in mind that this is a single point model (ie: one fleet). The only practical limits to consider here are the number of buses in the fleet. A practical minimum is 10 vehicles, otherwise the model becomes less accurate due to difficulties of supply matching demand and plant capacities not being representative. There is no upper fleet size limit, but the figure used in the CUTE future scenarios, identified a typical fleet as 73 vehicles.

### 1.2.2 Fleet Vehicle performance data

Fleet vehicle Fuel data					
		Hydrogen		Diesel	
Average fuel consumption	kg Diesel / km	0.2 to 0.31	0.25	0.27 to 0.37	0.368
Bus emissions	kg CO2 / km	0.00	0.00	1.16 to 3.96	3.96
Cost of Fuel (gross)	£ / litre			1.00	1.05

**Figure App 4–3 Hydrogen and Diesel bus performance data**

This section enables the user to input the data relative to the performance of the hydrogen and diesel buses. The advisory data for hydrogen is taken directly from the CUTE project. The diesel bus data is taken from a variety of sources. The cost of diesel fuel is the pump price inclusive of all taxes. The cost basis of the model excludes all taxes and duties which were valid in 2007. All results and costs for both hydrogen and diesel are reported on this basis.

Input or cell	Data	Source
Average hydrogen fuel consumption	CUTE final report Min / Average / Max = 0.204 / 0.248 / 0.315 kg H <sub>2</sub> / km	(CUTE, 2006, p67)
Hydrogen bus emissions	Zero emissions claimed	-
Average diesel fuel consumption	CUTE deliverable No.6 – 49 litres per 100km = 0.368 kg Diesel per km  Gavin Clark of customers services at TFL 36.241 litres/100km (5.383 mpg) = 0.27 kg / km  DFT web site 2.5 km / l of diesel = 0.3 kg / km	(Binder M and Faltenbacher M, 2006, p4)  (Clark G, 2004)  (DFT, 2008)
Diesel bus emissions	The impact of CO <sub>2</sub> emissions can be calculated from fact that burning one litre of fuel gives rise to 3.2 kg of CO <sub>2</sub>  based on fuel consumption range of 0.27 to 0.37 kg diesel / km, this would equate to a range of 1.16 to 1.578 kg CO <sub>2</sub> / km  Gavin Clark of customers services at TFL  Hydrocarbons g/km: 0.023 = 0.5 g CO <sub>2</sub> e NOX: 10 g/km = 2960 g CO <sub>2</sub> e / km CO <sub>2</sub> : 994 g/km = 994 g CO <sub>2</sub> e / km CO: 0.136 g/km= n/a  CO <sub>2</sub> e equivalents, total = 3955 g CO <sub>2</sub> e / km  Based on:- 1 CO <sub>2</sub> = 1 CO <sub>2</sub> e, 1CH <sub>4</sub> = 23 CO <sub>2</sub> e, 1 NOX = 296 CO <sub>2</sub> e, 1 HFC = 1100 CO <sub>2</sub> e The discrepancy between these two set of figures can be explained by NOX emissions included in the TFL figures.	(DFT, 2008)      (Clark G, 2004)

Figure App 4–4 Fleet performance data and sources

### 1.2.3 Energy data

Energy data - base costs					
Biomass wood chip feed stock	0.04 to 0.08	0.08	£ / kg		
Gas	0.0159	0.02	£ / kwhr		
Electricity mix and cost options					
		Fuel mix %		Generating costs / kwhr	
		UK avg mix	User choice	typical	User choice
Coal		35.20	35.20	£0.030	£0.030
Natural Gas		39.70	39.70	£0.023	£0.023
Nuclear		20.90	20.90	£0.024	£0.024
Renewables		04.20	04.20	£0.049	£0.049
		Balance	0.00%		

## Figure App 4–5 Energy costs and emissions

This section relates to the basic to energy used in the hydrogen pathways for both production and delivery. It is used in calculations for costs and emissions of production, compression etc. Costs are adjustable as shown above, although as gas prices tend to fluctuate with oil prices, it is difficult to give an advisory figure here. The figure given in the table is taken from the CUTE project, but the user would typically use current or forecast costs.

The UK average mix for electricity is a proportional breakdown of the different types of electricity generation currently used in the UK. These figures would be realistic if the electricity used in the model were taken from the grid. The model allows for variation in the methods of generation. This is necessary to compare the effects of different types of generation on both cost and overall emissions on the pathways.

The cost of electricity figures here are based purely for generation. No allowance has been made for transmission, operating profit margins etc. These costs are addressed separately in section 1.3.2.

Emissions are fixed within the model for each type of fuel used for electricity generation. Natural gas used as a fuel (eg: SMR process) calculates the emissions used in total during the process of hydrogen manufacture and therefore appears on the relevant results for hydrogen production

Input or cell	Data	Source
Gas	CUTE deliverable No.6 € 0.05 per kWh	(Binder M and Faltenbacher M, 2006)
Electricity		(Ruffles P, 2004, p8 - 9)
Coal	Coal fired pulverised fuel (steam plant) = £0.025 / kWh Coal fired circulating fluidised bed (steam plant) = £0.026 / kWh Coal fired Integrated Gasification Combined Cycle (IGCC) = £0.032 / kWh	
Natural gas	Average = £0.028 / kWh, Allowing for inflation gives = £0.030 / kWh Gas fired combined cycle gas turbine Nuclear Fission plant = £0.022 / kWh Allowing for inflation gives = £0.022 / kWh	
Nuclear	Nuclear Fission plant = £0.023 / kWh Allowing for inflation gives = £0.024 / kWh	
Renewables	On shore wind farm = £0.037 / kWh Off shore wind farm = £0.055 / kWh  Average = £0.046 Allowing for inflation gives = £0.049 / kWh	

Figure App 4–6 Energy data and sources



1.2.4 Supply chain data

Hydrogen - Transportation						
Supply chain length (min 25 / max 200 km)			200	km		
Av speed (km/hr)	46.4	Pipeline length (Urban)		50%	km	
	78.4	Pipeline length (Rural)		50%	km	
	Pipelines / Storage		Compressors / plant		Road tankers	
Capex life (years)	50	50	25	20	25	25
Opex costs (% Capex p.a)	2	2	5	5	5	5

Figure App 4-7 Supply chain data

This section relates to the length of the supply chain, the type of terrain that any pipeline will travel through and the capital and operating costs of the various pieces of equipment. The supply chain length is self explanatory and is relevant only to the centralised production methods. Due to the method of calculating costs, practical limits of between 25km and 200km need to be applied, for reasons which will be explained further in section 1.3.4.3. Whilst a pipeline can technically be hundreds of kilometres, a practical maximum distance of 200 km is a reasonable limit for the UK as it is unlikely that a hydrogen fuelling station would be any further than this distance from a current UK hydrogen production plant.

Pipeline costs vary significantly with terrain. Costs to cross a busy city could be significantly more expensive than crossing rural farmland. One of the features of this model is that it gives the user some degree of flexibility to determine pipeline costs based on terrain. Most other research models appear to use generic costs per km regardless of the type of terrain covered. The method of calculating pipeline costs will be addressed further in the section 1.3.4.3.

Just as pipeline costs vary by terrain, so do the costs of delivery by road tanker. Average speeds in towns and urban areas are likely to be different when compared with motorways or dual carriageways. This affects the deliveries that a single tanker can make in one day. The model allows the user to input two different values to reflect this and the average speed is calculated using the percentage of rural / urban terrain. The figures used here were obtained from typical Department for Transport statistics for HGV vehicles on different types of roads (Anderson D, 2008).

CAPEX (Capital expenditure) & OPEX (Operating expenditure) are typical industry methods to determine whole life costs. Generally low maintenance items, such as pipelines, have long CAPEX life and small OPEX costs.

The capital cost of equipment is usually defined as the cost to plan, design, supply, build and put a piece of equipment into service. To calculate the total cost of producing hydrogen, it is normal to estimate how long the equipment will last. This is known as the CAPEX life. To a certain extent, these figures are only approximations as the operating life of a plant is also a function of the original quality of build (and hence capital cost) and also being properly maintained.

The operating cost in this context relates to the ongoing costs for maintenance of the plant and other running costs such as employee wages etc is usually quoted as a percentage of the capital cost per annum. It does not however include production costs such as feedstock.

Whilst CAPEX costs are quite well defined and generic in the sense that the actual cost of the process plant is similar regardless of where the equipment is installed, OPEX costs are dependent on local factors such as land costs, local taxes and wages etc. However it is normal practice to use these parameters, whereby one is expressed as a percentage of the other.

### 1.3 Inputs worksheet

This worksheet is to enable more advanced users to input variables for use on other worksheets in the model. Unlike the inputs data sheet there are some quite complex calculations, look up tables and visual basic routines in this sheet. All the user adjustable variables that appear on the user interface worksheet are replicated here for clarity. Where appropriate, the cells have been highlighted using the track precedent / dependent function in Excel to aid the reader.

INPUTS SHEET
User input cell - can be modified to any value - guidance on practical values (where appropriate) in pale yellow
Recommend practical value for user guidance - located adjacent to user input cell
User input cell - available on User Interface sheet only
Cell which is populated using selection buttons.
Protected fixed value cell or calculation

Figure App 4–8 Key to colour coding on inputs sheets

The colour codes used in this worksheet are exactly the same as the user interface work sheet with two additions:-

- Green cells contain data that have been copied over from the user interface worksheet.
- Clear cells contain formulae and calculations.



In addition there are cells to the right of the main worksheet area, which used as look up tables and for additional off screen calculations. Where appropriate, explanations have been included here. These figures are identified by the words “off screen area”.

### 1.3.1 Fleet vehicle details

Fleet vehicle details					
		Hydrogen		Diesel	
No. of Buses		100		100	
Operating hours per day		12	hours	12	hours
Average speed		20	km / hr	20	km / hr
No. of operating days / year		360	days	360	days
Average fuel consumption		0.25	kg H2/km	0.368	kg Diesel / km
Bus emissions		0.00	kg CO2 / km	3.96	kg CO2 / km
Fuel requirement		5,870.47	kg / day	8,711	kg / day
		244.60	kg / hr	363	kg / hr
Cost of Fuel (gross)		-	£ / kg	1.05	£ / litre
Cost of Fuel (Nett of tax)		calculated	£ / kg	0.43	£ / kg

Figure App 4 – 9 Fleet fuel requirements

This section contains information that has been inputted in the user interface sheet, it calculates the quantities of fuel used for the selected variables. The hydrogen fuel requirement is then used in further calculations to select production plant sizes and transportation.

### 1.3.2 Energy data

Energy data						
Gas		Base costs		0.0357	£ / kwhr	
Electricity options						
	% Composition		Generating costs £ / kwhr		Emissions	kg CO <sub>2</sub> / kWhr
	Uk average	User choice	Typical	User choice	Uk avg	0.46
Coal	• 35.20	• 35.20	0.090	0.090	user choice	0.46
Natural Gas	• 39.70	• 39.70	0.023	0.023	Cost	£ / kWhr
Nuclear	• 20.90	• 20.90	0.024	0.024	Uk avg	0.0738
Renewables	• 04.20	• 04.20	0.049	0.049	user choice	0.0738
Gas Options						
It is assumed that gas price is constant regardless of source of gas - this is reasonably applied to Natural Gas. Other gases such as LPG are not considered in these scenarios for energy data. Consequently the gas price in cell E19 is not a variable in this model. Furthermore Electricity price has a greater effect on overall cost than gas with the exception of gas feed for SMR's.						

Figure App 4–10 Energy costs and emissions data

Input or cell	Data	Source
Electricity generation emissions	From figure 2 page 982 Direct emissions from:- Coal = 960 g CO <sub>2</sub> / kWh Natural Gas = 460 g CO <sub>2</sub> / kWh Nuclear and renewables are considered to be emissions free for the purposes of this exercise  Direct emissions from:-	(Markandya A and Wilkinson P, 2007)       (POST, 2006, fig 2 & 3)

	Coal = 810 g CO <sub>2</sub> / kWh Natural gas = 410 g CO <sub>2</sub> / kWh Nuclear and renewables, typically ≈ 5 g CO <sub>2</sub> / kWh	
--	--	--

**Figure App 4–11 Energy costs and source**

This section replicates the data from the user interface sheet on electricity generation costs and emissions. The emissions values are calculated by summation from the cells as shown for details in Figure App 4-10. The electricity generation costs are more complex, the figures so far are for generation costs only, for a complete figure, it needs to include transmission costs and losses, distribution costs and operating profit margins. This is addressed in the electricity cost section, see below for details.

Electricity cost section			
I have tried to provide flexibility here to calculate electricity cost variations. I have taken the basic cost cost of generating and "average" uk costs in 2007 - look at formulae to understand			
4%	Trans. Costs	17%	Distrib. Costs
10%	Trans losses	33%	Operating margin
This bit is just used to calculate the component costs of electricity			
0.01056	0.01056	See calculations below	
0.009131	0.009131		
0.005016	0.005016		
0.002058	0.002058		
Typical example prices (Dec 2007)		Generating cost	£0.0268
	£ / kwhr (net tax)	average del. Cost	£0.0738
CUTE	£0.0714	Trans. Costs	£0.0030
Business	£0.0812	Trans. losses	£0.0074
Domestic	£0.0671	Distrib. Costs	£0.0125
Domestic green	£0.0754	Profit	£0.0244

**Figure App 4–12 Electricity cost section**  
(off screen area)

The electricity costs section the total delivered cost of electricity. The arrows show the contributions each cell makes to the overall cost. It appears complex, but is easily explained. The blue cells are the user input cells and should be self explanatory.

**Note: These values should only be adjusted by users with sufficient knowledge of electricity generating costs**

The only other cells which need further explanation are the calculations cells in the bottom right hand corner of Figure App 4-12. It is assumed that the transmission and distribution costs as well as the operating profits are largely independent of the generating costs. Consequently they have



1. Generating cost is the sum of the components of the electricity generation, coal, gas etc.
2. Average delivered cost is taken as the average of some known costs as shown by the dependence arrows above.
3. Transmission costs are the user defined portion (4%) of the average delivered cost
4. Transmission losses are the user defined portion (10%) of the average delivered cost
5. Distribution costs are the user defined portion (17%) of the average delivered cost
6. Operating margin (profit) is the user defined portion (33%) of the average delivered cost

Input or cell	Data	Source
Electricity supply costs	Government Post note 280 Electricity in the UK <ul style="list-style-type: none"> <li>• Transmission losses</li> <li>• Operating profits</li> </ul>	(POST, 2007, p2)  Assumption from typical industry figures This figure is difficult to obtain, due to commercial sensitivity. The figure of 33% has been calculated using known generating costs against known sales costs.

Figure App 4–13 Energy cost and source

1.3.3 Production / Liquefaction and Sequestration

		Hydrogen - Production / Liquefaction				
Sequestration		Cost per kg of Hydrogen				
No Sequestration			Reforming	Electrolysis	Biomass	Liquefaction
Centralised	Capital plant cost	£	£1.29	£3.73	£1.37	£0.89
	Plant capacity	kg / day	77,940,000	52,425,000	62,155,514	23,120,000
	without CO <sup>2</sup> seq.		£1.11	£3.44	£1.40	£0.66
	with CO <sup>2</sup> seq.		£1.51	n/a	£1.79	n/a
	Selected		£1.11	£3.44	£1.40	£0.66
Localised			For plant selection and calculation refer to Production worksheet			
	selected		£1.71	£4.76		
		Emissions (kg CO <sub>2</sub> per kg of Hydrogen)				
			Reforming	Electrolysis	Biomass	Liquefaction
Centralised	without CO <sup>2</sup> seq.		9.28	27.82	4.91	0.66
	with CO <sup>2</sup> seq.		0.93	n/a	0.49	n/a
	Selected		9.28	27.82	4.91	0.66
Carbon reduction efficiencies %		(note 2)	90.00		80.00	
Localised			9.28	27.82		

Figure App 4–14 Hydrogen production costs and emissions

This section calculates the costs and emissions of the hydrogen production stage of the pathway. It is separated into centralised production and localised production. It also calculates liquefaction costs and has the facility to include for carbon capture and sequestration (where appropriate).

Centralised production costs are considered on the basis of large scale production plants and hence are independent of demand. This is because hydrogen has multiple uses and markets and hence centralised production facilities do not need to be built to supply one depot. Localised production requires supply to match demand, so there are few user inputs here that are variable. The model attempts to minimise errors due to the wide variations in production costs by using a variety of sources for data and attempting to match appropriate costs to demand, particularly in the local production pathways. This also includes the US DoE model values reviewed earlier for comparison purposes.

The Biomass production figures are based on farmed woodchip. It would be possible to adjust this in the model by changing the energy costs identified in Figure App 4-5, however it is possible that other costs such as CAPEX and OPEX may vary, so detailed analysis of the specific pathway may be required.

Purification of the hydrogen is required in the reforming and biomass processes to bring it up to the purities required for fuel cells. Costs have been allowed for in the production worksheet. Some costs are estimated but are a relatively small percentage of the overall costs as can be seen in Figure App 4-15 Liquefaction costs are required for liquid hydrogen truck pathways.

The model has a select button to include for both the cost increase and emissions reduction of carbon capture and sequestration. At the time of writing, demonstration projects are only just beginning in Europe and consequently, real data on operating costs and technical performance is not yet readily available. Costs in this model are based on the US DoE figures. This option has no effect on localised production, due to the fact that it is unsuitable due to the storage requirements of the CO<sub>2</sub>.

**Until such time as realistic data is available, results from using this select button should be treated with caution**

Note (2) in Figure App 4-14 relates to the efficiencies of the biomass and carbon sequestration processes. The carbon reduction efficiency for reforming is the % that can be removed as part of the sequestration process. The Biomass reduction efficiency is the % of carbon produced in the



process that is assumed to be consumed as part of the growing process. Although user adjustable, they are set for all scenarios in chapter 8 on modelling.

The production work sheet shown in Figure App 4-15 below has been added to improve accuracy in calculating production costs. There are virtually no user inputs as it takes most of its data from the input sheet and reports back to the input sheet. It is in effect the production calculation module referred to in chapter 7. The only user input cells are the “plant operating rate” data which although adjustable, should only be adjusted if the user has significant experience in this area. The figures used in the model were calculated by carrying out discrepancy tests between the Research and US DoE models.

Centralised production							
	Units	Purification	Reforming	Electrolysis	Biomass	Liquefaction	sequestration
Capital equipment cost	£	500,000	£77,940,000	£52,425,000	£62,155,514	£23,120,000	£300,000,000
Plant capacity	kg / dy	9,600	379,387	52,300	140,000	30,000	379,387
CAPEX life	years	20	20	20	20	20	20
OPEX rate	% pa	5	5	5	5	5	5
Plant operating rate	% pa	1	12	9	8	5	5
Total CAPEX cost per kg H2		£0.0075	£0.0296	£0.1445	£0.0640	£0.1111	£0.1140
Total OPEX cost per kg H2		£0.0075	£0.0296	£0.1445	£0.0640	£0.1111	£0.1140
Total plant running costs		£0.0015	£0.0711	£0.2602	£0.1024	£0.1111	£0.1140
Total plant costs	/kg H2	£0.0165	£0.1303	£0.5493	£0.2305	£0.3334	£0.3421
Energy requirements							
Feedstock	see comment		4.501	53.440	12.839		
	kwhr		46.260	53.440			
Feedstock cost			0.020	0.064	0.080		
Utility 1 - Electricity	kwhr / kg H2		0.855		1.600	5.005	0.860
Utility 2 - Gas	Nm3 / kg H2				0.170		
	kwhr				1.747		
Total Energy costs	/kg H2		£0.98	£3.44	£1.17	£0.32	£0.06
Total cost per kg H2			£1.11	£3.99	£1.40	£0.66	£0.40
Total emissions per kg H2	kg CO2e		9.28	27.82	24.57	2.61	0.45

Localised Production							
	Units	Purification	Reforming	Electrolysis	Biomass	Liquefaction	sequestration
Capital equipment cost	£		£6,218,386	£18,596,958			
Plant capacity	kg / dy		4,892	4,892			
CAPEX life	years		20	20			
OPEX rate	% pa		5	5			
Plant operating rate	% pa		10	7			
Demand	kg/dy		4,892	4,892			
Total CAPEX cost per kg H2	per kg H2		£0.1833	£0.5482			
Total OPEX cost per kg H2	per kg H2		£0.1833	£0.5482			
Total plant running costs	per kg H2		£0.3666	£0.7674			
Total plant costs	/kg H2		£0.7332	£1.3156			
Energy requirements							
Feedstock	see comment		4.501	53.440			
	kwhr		46.260	53.440			
Feedstock cost			0.020	0.064			
Utility 1 - Electricity	kwhr / kg H2		0.855				
Utility 2 - Gas	Nm3 / kg H2						
	kwhr						
Total Energy costs	/kg H2		£0.98	£3.44			
Total cost per kg H2			£1.71	£4.76			
Total emissions per kg H2	kg CO2e		9.28	27.82			

Figure App 4–15 Production worksheet layout





	40Mj * 75% (electric driven compression) = 30 MJ based on emissions of electricity * 30 MJ / 3600 s = answer	
Hydrogen purification	CAPEX costs of say £500,000 for a small Hydrogen PSA 250 kg/hr @25 years and 2% p.a OPEX cost, catalyst £100,000 change out every 5 years. Assume plant availability of >90%.  This equates to approx £0.025 / kg	Estimate based on author's experience
Carbon Sequestration	Table 3.2 Defines costs of sequestration as £/kg 0.78-0.47 = 0.31 per kg Allowing for inflation = this equates to approx 40p / kg of hydrogen	(Haydock H et al., 2003, p17)
	Table 3.6.2 Defines carbon capture efficiency of hydrogen from Natural gas reforming as 83.6%. It is assumed that similar efficiencies can be achieved from Biomass as the reforming step is similar to natural gas reforming.	(Edwards R et al., 2007, p52)
<b>Localised Production</b>		
SMR	Costs are generally based on CUTE based on the following assumptions:- 1. Capital costs are taken as - CUTE minimum = £5.06 per kg H <sub>2</sub> 2. Operating costs are taken as - CUTE minimum = £3.89 per kg H <sub>2</sub> 3. CUTE gas cost = £ 0.0357 per kWh 4. Actual gas cost = User interface sht E17 5. Assumption that energy cost = 75% of operating cost  To allow for energy variation costs (gas in the case of SMR) the total cost has been calculated on the following basis –  Cost = 1 + (2 *0.25) + (2*0.75*(4/3))	(Binder M and Faltenbacher M, 2006)
Electrolysis	6. Capital costs are taken as - CUTE minimum = £3.10 per kg H <sub>2</sub> 7. Operating costs are taken as - CUTE minimum = £4.14 per kg H <sub>2</sub> 8. CUTE elec cost = £ 0.074 per kWh 9. Actual gas cost = Inputs sheet G30 10.Assumption that energy cost = 75% of operating cost  To allow for energy variation costs (gas in the case of SMR) the total cost has been calculated on the following basis –  Cost = 1 + (2 *0.25) + (2*0.75*(4/3))	
Plant capacities	Scaling of plants are carried out using the 6/10ths rule referred to in the CUTE future scenarios.	

Figure App 4–16 Production data sources

1.3.4 Storage and vaporisation



Hydrogen - Storage / Vaporisation					
On site storage & vaporisation	Cost per kg of Hydrogen				
	basis of data	GAH storage	LIH storage		Vaporisation
	NREL report	£0.40	£0.66		£0.0463
	CUTE report	£0.23 to £0.71	£0.89		
		£0.40	£0.66		£0.05
	Emissions (kg CO <sub>2</sub> per kg of Hydrogen)				
		GAH storage	LIH storage		Vaporisation
Storage = hydrogen leaks only		0.00	0.00		0.00
Vaporisation = zero if "Ambair" vaporisers are used		0.00	0.00		0.00
Notes					

**Figure App 4–17 Hydrogen storage and vaporisation costs and emissions**

This section relates to the costs and emissions of hydrogen storage (both liquid and gaseous), and vaporisation in the case of liquid hydrogen that needs to be vaporised before compression and storage on board the buses in gaseous form. Emissions due to hydrogen storage can be considered as either zero or negligible, particularly if Ambair vaporisers are used. Ambair vaporisers are heat exchangers which rely on the ambient air to warm the cryogenic liquid. These are particularly suitable for small quantities of gas with a relatively low flow rates and used intermittently. Costs are dependent on storage volumes, which in this case is a function of the fleet size and delivery medium.

For liquid hydrogen storage, the maximum required capacity is likely to be about 4000kg which allows for one tanker delivery of 3600kg plus reserve capacity. This would equate to a tank of about 65m<sup>3</sup> and have the capacity to provide enough hydrogen for about 16,000km of bus travel, large enough for any practical fleet size. For gaseous hydrogen stored at high pressure the issue of capacity is more significant due to the lower storage density. However hydrogen high pressure storage tends to be stored in multiply "bullet" type storage tanks and capacity is increased by increasing the number of storage tanks. For these reasons, it is appropriate to ignore the potential for economies of scale and assume that a relatively generic cost as shown in Figure App 4 -17 is appropriate.

The capital cost of a typical vaporiser is assumed to be in the region of £50,000 for a piece of equipment with a capacity of 500kg / hr. It is assumed to have similar CAPEX and OPEX cost characteristics as pipelines (long life / low maintenance). With these assumptions, the cost is relatively small. Doubling or even tripling the capital cost would still not have a significant effect on

vaporisation costs. For this reason, no further work has been done establishing more accurate cost data for vaporisation.

Input or cell	Data	Source
Hydrogen storage	<ul style="list-style-type: none"><li>Gaseous hydrogen storage - table 7 page 22. Costs are quoted in 1998 and have been adjusted for inflation to 2007 prices.</li><li>Liquid hydrogen storage - Appendix figure 3. Assuming flows in the range of 25 to 250 kg /hr. Costs vary between \$1.2 to \$0.8 / kg H2 and have been adjusted for inflation to 2007 prices.</li></ul>	(Amos W, 1998)
	<ul style="list-style-type: none"><li>Gaseous hydrogen storage – figure 3 page 18</li><li>Liquid hydrogen storage – figure 5 page 22</li></ul>	(Binder M and Faltenbacher M, 2006)

Figure App 4–18 Storage and vaporisation data and sources

1.3.4.1 Compression

Hydrogen - Compression						
		Cost per kg of Hydrogen				
			production to tanker loading	Storage to bus via tanker	Storage to bus via pipeline	Pipelines
CAPEX life (years)		CAPEX	0.004564	0.003239	0.006811	0.002686
	25	OPEX	0.000228	0.000162	0.000341	0.000134
OPEX costs (% CAPEX p.a)		Power	0.144881	0.012461	0.072066	0.085276
	5		£0.15	£0.02	£0.08	£0.09
		Emissions (kg CO <sub>2</sub> per kg of Hydrogen)				
			production to tanker loading	Storage to bus via tanker	Storage to bus via pipeline	Pipelines
			1.02	0.09	0.51	0.60
		Power calcs				
Hydrogen properties		refer to note 2 before changing	production to tanker loading	Storage to bus via tanker	Storage to bus via pipeline	Pipelines
R (kJ / kg C)	4.12	P <sub>in</sub> (Bar A)	005	250	050	005
T (K)	293	P <sub>out</sub> (Bar A)	250	350	350	050
Efficiency	0.67	Power (kwhr / kg)	1.958	0.168	0.974	1.152

Figure App 4–19 Hydrogen compressor data

The compression section calculates compressor power, cost and emissions, for all compression requirements of the various pathways:-

- Loading at production plant to road tanker (typically 5 to 250 bar g)
- Pipeline transmission compression requirements (typically 5 to 50 bar g)
- Loading at filling station on to buses (typically 5 to 350 bar g or 250 to 350 bar g)

Inlet and outlet pressures are adjustable as is the efficiency of the compressors. It is assumed that compressors are driven by electric motors and hence cost and emissions are calculated using the



electricity generation data in section 1.3.2. Thermodynamic properties of hydrogen, required to calculate power requirements are fixed in the model.

This module calculates all compression data required for the various components of the model. It includes loading on to tankers for transportation, fleet vehicles, pipelines as well as liquefaction compression requirements. It uses a basic compressor power equation:-

**Power = Mass flow \* R \* T \* (LN(Pin/Pout)) / e)**

Where:-

R = Specific gas constant (kJ/kg K)

Pin = -suction pressure (bar absolute)

T = temperature (K)

Pout = discharge pressure (bar absolute)

e = efficiency (typical 0.67 for a reciprocating compressor)

Compression power calculations have been validated against Thomassen compressors web site calculator and results found to be within 10% margin of error when compared to equivalent calculations in this model (Afd. Verkoop Compressoren, 2000). This is a relatively "generic" set of data as compressors are normally closely matched to duty. The type of compressor assumed is reciprocating with a typical efficiency. Inputs to the compressor power calculation are shown using the Excel trace precedent function in Figure App 4 - 19.

It is recognised that the transfer of hydrogen in gaseous state will lead to some losses in terms of energy as additional compression is required to transfer between the tanks. The model takes this into account in the compressor power calculations. Although it may not be possible to transfer all the contents of the delivery truck into the static tank due to minimum compressor suction pressures, consequently it does mean that a full load may not be transferred.

Once the compressor power requirements have been calculated, it uses look up tables to determine optimum compressor sizes and energy input data, assuming that an electric motor driven compressor is used. This gives output costs and emissions which are used elsewhere as shown in the diagram.

Input or cell	Data	Source																
	<p>Capital equipment costs are taken from p17 table 1</p> <table><tr><th>comp rating</th><th>\$/kw</th><th>£/kw</th><th>£/kw (2007)</th></tr><tr><td>10</td><td>6600</td><td>3667</td><td>4212</td></tr><tr><td>75</td><td>2400</td><td>1333</td><td>1532</td></tr><tr><td>250</td><td>800</td><td>444</td><td>511</td></tr></table> <p>Basic compressor power calculation used :- (Mass flow * R * T * LN(Pin/Pout)) / efficiency</p>	comp rating	\$/kw	£/kw	£/kw (2007)	10	6600	3667	4212	75	2400	1333	1532	250	800	444	511	(Amos W, 1998)
comp rating	\$/kw	£/kw	£/kw (2007)															
10	6600	3667	4212															
75	2400	1333	1532															
250	800	444	511															





1.3.4.2 Tanker transportation

Diesel / Hydrogen - Transportation - Tanker							
CAPEX	20	Supply chain distance - From centralised production facility to point of filling			30	km	
OPEX	10						
	Fuel Cell truck data	Diesel truck data	Tanker / Trailer data				
			Diesel	SOLID HYDROGEN PATHWAY DATA RESERVED FOR FUTURE USE	Gaseous H <sub>2</sub>	Liquid H <sub>2</sub>	
CAPEX cost	£310,050	£58,500	£50,000		£103,000	£266,000	
	£310,000	£58,500	£50,000		£103,000	£266,000	
OPEX cost p.a	£31,000	£5,850	£5,000		£10,300	£26,600	
Capacity (kg)			20,000		460	4,000	
Pressure (barg)			2		220	2	
Required (kg/dy)			8,711		5,870	5,870	
Load time (hrs)			0.50		0.50	1.00	
Unload time (hrs)			0.50		1.00	0.50	
Truck payload pf. (note 1)			5.00		0.12	1.00	
			5.00		0.12	1.00	
av speed (km/hr)	km / hr	60					
Labour costs	£ p.a / employee	30,000					
Operating time	hrs / day	12					
Diesel truck	Delivered cost £ / kg		£0.005			£0.134	£0.022
	Emissions kg CO <sup>2</sup> / kg fuel		0.0594			0.0620	0.0594
FCV truck	Delivered cost £ / kg		£0.011			£0.202	£0.034
	Emissions kg CO <sup>2</sup> / kg fuel		0.0000			0.0000	0.0000
Diesel truck	FCV truck	Costs £ / kg	0.005			0.134	0.022
		Emiss. kg CO2 / kg	0.059			0.062	0.059
Diesel Truck							

Figure App 4–21 Truck data

This section enables the user to input specific data related to the cost and time of delivery of the hydrogen and diesel by road. Most of the cells are self explanatory and where appropriate, advisory values are shown in yellow. Delivery requirements are calculated in a separate section and results shown here (refer to Figure App 4-22 below). There are two specific areas that merit specific explanation:-

- The model has the facility to select delivery by either diesel powered or hydrogen powered fuel cell trucks. The reason for this is that if hydrogen is a viable fuel alternative to diesel for fleet vehicles, it is logical that the trucks that deliver the hydrogen could also be powered by hydrogen. This is carried out using the two select buttons “Diesel truck” and “FCV truck” shown in the bottom left hand corner of Figure App 4-21. It would be necessary if the aim was a truly zero carbon supply and distribution system.
- There are input cells labelled “truck payload pf” (power factor). All truck costs, including fuel consumption are calculated on the same basis, regardless of payload. Different payloads would affect the fuel consumption of the delivery trucks. For example, a diesel payload is forty three times heavier than gaseous hydrogen, the fuel consumption requirements would

therefore be skewed if common truck performance data were used. This cell attempts to compensate for this in the overall fuel consumption figures.

Delivery by Diesel truck				
Diesel	Solid H <sub>2</sub>	Gaseous H <sub>2</sub>	Liquid H <sub>2</sub>	
21700.00	16000.00	32500.00	64900.00	Equipment cost £ p.a
5.02	3.70	7.52	15.02	Equipment cost £ per operating hour
16.67	16.67	16.67	16.67	Labour cost £ per operating hour
47.64	7.15	1.14	9.53	Cost of truck fuel £ per journey
21.69	20.37	24.19	31.69	Total cost £ per operating hour
0.44	1.96	12.76	1.47	Deliveries required (per day)
2.00	2.00	2.50	2.50	Delivery time per tanker load (hours)

Delivery by FCV truck				
Diesel	Solid H <sub>2</sub>	Gaseous H <sub>2</sub>	Liquid H <sub>2</sub>	
72000.00	68000.00	82800.00	115200.00	Equipment cost £ p.a
16.67	15.74	19.17	26.67	Equipment cost £ per operating hour
As per Diesel truck				Labour cost £ per operating hour
143.49	21.52	3.44	28.70	Cost of truck fuel £ per journey
33.33	32.41	35.83	43.33	Total cost £ per operating hour
As per Diesel truck				Deliveries required (per day)
As per Diesel truck				Delivery time per tanker load (hours)

Figure App 4–22 Truck delivery calculations

This section uses data shown above to calculate delivery requirements based on demand. It calculates the delivery costs of the hydrogen based on variables such as capital and operating cost. It also calculates delivery time based on supply chain length, speeds and loading times etc. This is necessary to determine how many deliveries can be made by one tanker per day and hence provide a realistic cost of delivery.

It should be noted that due to the way that the model calculates the number of tankers required and utilisation of tankers, it reports a slight error at the changeover point of approximately 1,000 kg per day. This error is relatively small (in the region of 1.2p / kg).

Input or cell	Data	Source
Fuel Cell truck cost	No data is readily available for these vehicles. Based on CUTE data which showed a FCV bus	
Diesel truck cost	Table 13 p 39 \$90,000 adjusted for inflation	(Amos W, 1998)
Diesel Tanker costs	Estimated cost	
Gaseous hydrogen tanker costs	table 13 p 39 Tubes \$100,000 + \$60,000 undercarriage adjusted for inflation	(Amos W, 1998)
Liquid hydrogen tanker costs	table 13 p 39 Tank \$350,000 + \$60,000 undercarriage adjusted for inflation	(Amos W, 1998)

Figure App 4–23 Transportation data and sources



1.3.4.3 Pipelines

Although this section contains no user input cells it is necessary to understand how the model calculates pipeline costs and emissions. It calculates the overall costs and emissions for a given set of data (Figure App 4-24), using a specific pipeline cost estimating tool (Figure App 4-25), based on pipeline sizing requirements using demand, pipe length and acceptable pressure drops (Figure App 4 - 26).

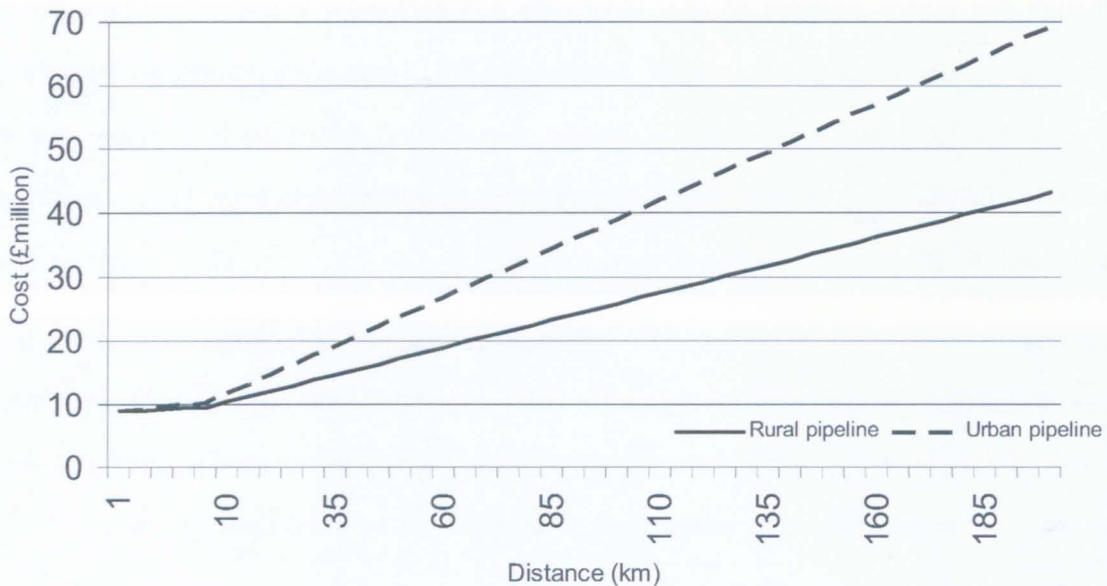
Pipelines are ideally suited to transport relatively large volumes of hydrogen gas across terrains where installation costs are relatively cheap (rural / open land). Although a single point model is unlikely to have very high demand it is still appropriate to model the pipeline option for all variation in supply and demand to identify where break even points are for the optimum pathway.

There are several elements to the pipeline calculation module. Firstly, an optimum pipe diameter is selected from look up tables correcting for demand and allowable pressure drop (due to gas velocities). There can be significant variations in the estimated cost of pipelines. This is partly due to variations in terrain, but it can also be “country specific” depending on issues such as labour costs and planning constraints.

Diesel / Hydrogen - Transportation - Pipeline				
CAPEX life (years)		Supply chain distance - From centralised production facility to point of filling		
	50		30	km
OPEX costs (% CAPEX p.a)		Pipeline Terrain selection	Urban	0%
	2		Cross country	100%
Hydrogen flow required	244.60	Pipeline costs	CAPEX Cost	£0.0014 per kg
	kg / hr		OPEX Cost	£0.0000 per kg
Pipeline size selected	6	Compressor costs	CAPEX Cost	£0.0027 per kg
	inches		OPEX Cost	£0.0001 per kg
Pipeline pressure loss per km	0.49		Power	£0.0853 per kg
	bars			
Total pipeline pressure loss	14.7			
	bars			
compressors required	001	Total transportation cost by pipeline		£0.09 £ / kg H <sub>2</sub>
	units	Total transportation emissions by pipeline		0.600 kg CO <sub>2</sub> / kg H <sub>2</sub>

Figure App 4–24 Pipeline cost and emissions

This section has no input cells, but shows the results of the pipeline costs and emissions of transporting the hydrogen by pipeline and is largely self explanatory.



**Figure App 4–25 Pipeline cost and estimates**

Specific pipeline costs are difficult to forecast as they are dependent on terrain and need to include for road and river crossings etc. It is therefore difficult to provide accurate costs without considering specific cases. The approach taken in this model is to assume two types of terrain, urban with a significant number of crossings etc. and rural whereby the majority of the pipeline crosses open land such as farmland. The tool used to calculate pipeline costs was provided by Penspen limited (Penspen, 2005). The two basic types of terrain were set up pipeline lengths were input from 0 to 200 km. Results were plotted (see Figure App 4-25) and within the range of 20 to 200 km, the slope obeys the mathematical straight line rule  $y = mx + c$ . This is used in the model to calculate pipeline costs according to length and terrain.

This graph is almost horizontal first the first few kilometres as the fixed costs such as project management dominate the overall cost. After that the length of the pipeline starts to dominate as the project management costs are a lower portion of the overall cost. This is why 20km is considered the practical minimum to be used in the model and although it appears that there is no practical maximum (assuming the straight line continues) this was not calculated and hence 200km is the recommended maximum to be used in this model. The main reason for the minimum of 20km is that the fixed costs of design and project are significant for short pipelines.



The pipeline calculations were based on 6" pipelines. Sensitivity analysis of the model showed that for varying pipeline sizes (in the range of 2" to 8"), the cost of the actual pipeline was not a major cost factor. Most of the cost is not in the pipe itself, but installation. Although the estimation tool is designed for natural gas pipelines using steel pipes, it should give reasonable results for hydrogen pipelines of medium pressure (less than 75 bar g) as the materials used would typically be similar for the two different gases, although this has yet to be established. The US DoE have carried out some research and concluded that *"a clear consensus with regard to the microalloyed API-type pipeline steels with respect to extent or occurrence of hydrogen embrittlement is lacking. Additionally, there is much evidence that the hydrogen purity plays a critical role in either increasing or decreasing the susceptibility of these materials to hydrogen embrittlement"* (US DoE, 2005). However, as in the case of pipe sizes, it is estimated that the cost increase for more expensive materials would not skew the overall costs significantly. It is important to note that the cost estimating provides the following warning on accuracy:-

**"The capital cost estimate is accurate only to +/- 25%"**

Pipeline capacity and pressure drop (bars / km) - look up tables			
H2 Flow	dp	H2 Flow	Line size
19		19	3
33	0.0630	33	3
38	0.0900	38	3
44	0.1200	44	3
49	0.1500	49	3
55	0.1900	55	3
82	0.2300	82	4
109	0.1300	109	4
164	0.2200	164	4
218	0.4900	218	6
245	0.1100	245	6
273	0.1300	273	6
	0.1600		

Pipeline cost estimations		
y = cost of pipeline (£)		
x = length of pipeline (km)		
For Urban pipeline	Total cost	£19,090,000
For cross country	Total cost	£15,160,000
Pipeline calculation was carried out on 6" pipe. Although 3" & 4" considered, it is assumed that at this pipe size, the actual pipe cost differential is insignificant		

Compressor selection	
dp (bars)	No.
0	1
045	2
90	3
135	4

Figure App 4–26 Pipeline look up tables

The primary purpose of these look up tables are to select the optimum pipeline size and hence calculate the costs of the pipeline based on the following:-

- Hydrogen demand as defined in Figure App 4-9
- Supply chain length and terrain as defined in Figure App 4-7.

It selects the optimum pipe sizes based on allowable pressure drops. It is worth noting that for all reasonable demands in this model the size of the pipeline has little effect on cost. It does however have an effect on pressure drop (due to increased velocities) and hence compression requirements. Costs of compression and emissions are based on the compressor power section

1.3.4.1. Pipeline costs based on the pipeline cost estimation tool as shown in Figure App 4 -25.

1.3.5. Results worksheet

		Step 1				Step 2				Step 3				Step 4					
		Production		Liquefaction		Compression (tanker loading)		Transportation			On site storage		Vaporisation		Compression (bus loading)		Totals / 100km		
		Cost	Emiss.	Cost	Emiss.	Cost	Emiss.	Cost	Emiss.	Dist.	Cost	Emiss.	Cost	Emiss.	Cost	Emiss.	Cost	Emiss.	
Cases		£ / kg	kg CO <sub>2</sub>	£ / kg	kg CO <sub>2</sub>	£ / kg	kg CO <sub>2</sub>	£ / kg	kg CO <sub>2</sub>	km	£ / kg	kg CO <sub>2</sub>	£ / kg	kg CO <sub>2</sub>	£ / kg	kg CO <sub>2</sub>	£	kg CO <sub>2</sub>	
CENTRALISED	C1 1111	01.29	05.52			00.15	01.02	00.13	00.06	30	00.40					00.02	00.09	049.33	165.90
	C4 1121	01.29	05.52					00.09	00.60	30	00.40					00.08	00.51	046.10	164.36
	C7 1211	01.29	05.52	00.80	04.34			00.02	00.06	30	00.66		00.00		00.08	00.51	070.75	258.53	
	C13 2111	01.37	00.00			00.15	01.02	00.13	00.06	30	00.40				00.02	00.09	051.32	028.99	
	C16 2121	01.37	00.00					00.09	00.60	30	00.40				00.08	00.51	048.08	027.45	
	C19 2211	01.37	00.00	00.80	04.34			00.02	00.06	30	00.66		00.00		00.08	00.51	072.74	121.62	
	C25 3111	04.25	25.51			00.15	01.02	00.13	00.06	30	00.40				00.02	00.09	122.84	661.55	
	C28 3121	04.25	25.51					00.09	00.60	30	00.40				00.08	00.51	119.60	660.01	
	C31 3211	04.25	25.51	00.80	04.34			00.02	00.06	30	00.66		00.00		00.08	00.51	144.26	754.18	
	CS1 CS2	SOLID HYDROGEN PATHWAY DATA RESERVED FOR FUTURE USE																	
	DIE		00.38						00.06	30							15.88	412.28	
LOCALISED	L1 11-1	04.90	05.52							30	00.40					00.08	00.51	133.45	149.48
	L7 31-1	04.77	25.51							30	00.40					00.08	00.51	130.14	645.13
						Key to cases			1	SMR	Gas	Road	Gas						
									2	Biomass	Liquid	Pipeline	Liquid						
										3	Electrolysis	Solid	Rail	Solid					

Figure App 4–27 Model results for a fixed set of conditions

This worksheet brings together all the results from the inputs and user interface worksheets. It enables the user to look at the at the cost of individual components of the pathway. The key to the cases are shown and where cells are blank it is because this step is not applicable for the relevant case.

1.3.6 Outputs worksheet



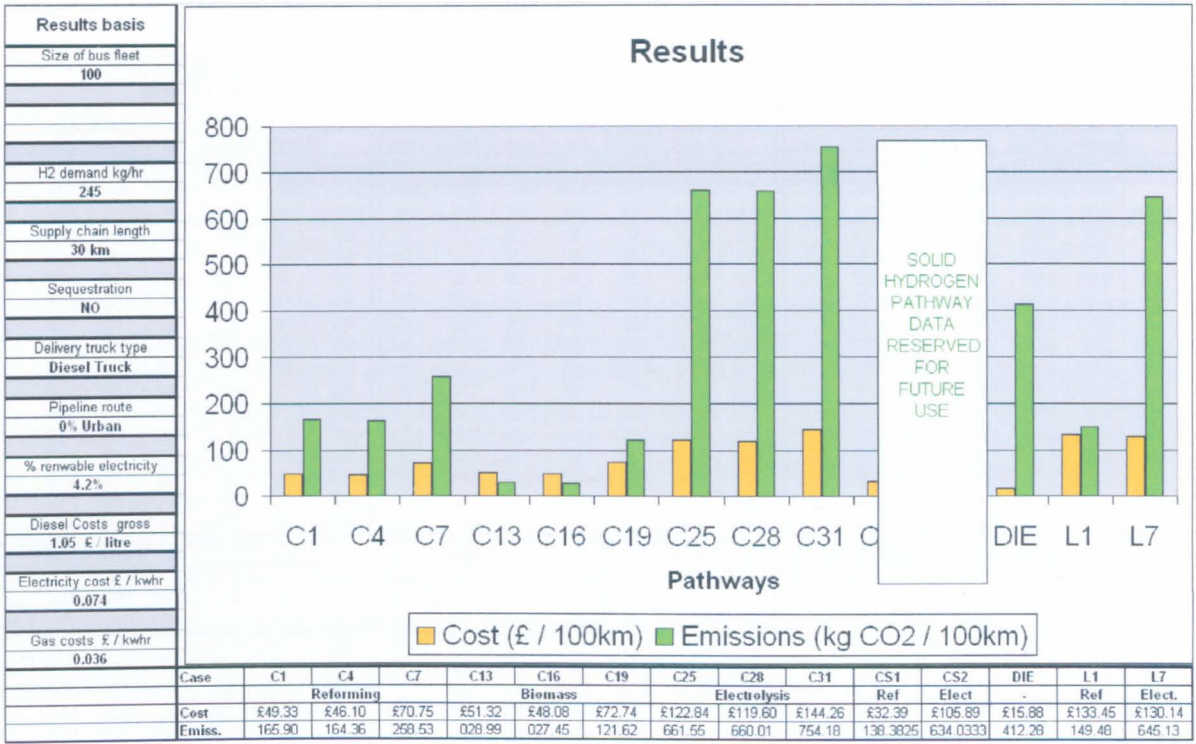


Figure App 4–28 Outputs for a fixed set of conditions

The outputs worksheet is intended to provide the user with a snapshot of results for a given set of conditions. By showing cost and emissions side by side, the user can compare the pathways based on either or both criteria. Whilst it can be exported to other worksheets it is intended that the results sheet is used for this purpose.

Appendix 5 – Raw data results from scenario SC2

Length 25 km Terrain 100% Urban							Length 25 km Terrain 50% Urban							Length 25 km Terrain 0% Urban						
demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>			demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>			demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>		
kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road	kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road	kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road
500	0.772	0.576	1.464	1.158	1.107	1.212	500	0.757	0.574	1.461	1.158	1.107	1.212	500	0.749	0.572	1.460	1.158	1.107	1.212
600	0.772	0.573	1.464	1.158	1.107	1.212	600	0.757	0.571	1.461	1.158	1.107	1.212	600	0.749	0.570	1.460	1.158	1.107	1.212
700	0.772	0.570	1.464	1.158	1.107	1.212	700	0.757	0.569	1.461	1.158	1.107	1.212	700	0.749	0.568	1.460	1.158	1.107	1.212
800	0.772	0.569	1.464	1.158	1.107	1.212	800	0.757	0.567	1.461	1.158	1.107	1.212	800	0.749	0.566	1.460	1.158	1.107	1.212
900	0.772	0.567	1.464	1.158	1.107	1.212	900	0.757	0.566	1.461	1.158	1.107	1.212	900	0.749	0.565	1.460	1.158	1.107	1.212
1000	0.760	0.566	1.464	1.158	1.107	1.212	1000	0.745	0.565	1.461	1.158	1.107	1.212	1000	0.737	0.564	1.460	1.158	1.107	1.212
1500	0.760	0.563	1.464	1.158	1.107	1.212	1500	0.745	0.562	1.461	1.158	1.107	1.212	1500	0.737	0.562	1.460	1.158	1.107	1.212
2000	0.760	0.554	1.464	1.158	1.107	1.212	2000	0.745	0.554	1.461	1.158	1.107	1.212	2000	0.737	0.553	1.460	1.158	1.107	1.212
2500	0.760	0.553	1.464	1.158	1.107	1.212	2500	0.745	0.553	1.461	1.158	1.107	1.212	2500	0.737	0.553	1.460	1.158	1.107	1.212
3000	0.760	0.553	1.464	1.158	1.107	1.212	3000	0.745	0.552	1.461	1.158	1.107	1.212	3000	0.737	0.552	1.460	1.158	1.107	1.212
3500	0.760	0.552	1.464	1.158	1.107	1.212	3500	0.745	0.552	1.461	1.158	1.107	1.212	3500	0.737	0.552	1.460	1.158	1.107	1.212
4000	0.760	0.552	1.464	1.158	1.107	1.212	4000	0.745	0.552	1.461	1.158	1.107	1.212	4000	0.737	0.551	1.460	1.158	1.107	1.212
4500	0.760	0.552	1.464	1.158	1.107	1.212	4500	0.745	0.551	1.461	1.158	1.107	1.212	4500	0.737	0.551	1.460	1.158	1.107	1.212
5000	0.760	0.551	1.464	1.158	1.107	1.212	5000	0.745	0.551	1.461	1.158	1.107	1.212	5000	0.737	0.551	1.460	1.158	1.107	1.212

Length 50 km Terrain 100% Urban							Length 50 km Terrain 50% Urban							Length 50 km Terrain 0% Urban						
demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>			demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>			demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>		
kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road	kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road	kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road
500	0.830	0.584	1.474	1.210	1.107	1.262	500	0.801	0.580	1.470	1.210	1.107	1.262	500	0.784	0.577	1.467	1.210	1.107	1.262
1000	0.818	0.570	1.474	1.210	1.107	1.262	1000	0.789	0.568	1.470	1.210	1.107	1.262	1000	0.772	0.567	1.467	1.210	1.107	1.262
1500	0.818	0.566	1.474	1.210	1.107	1.262	1500	0.789	0.564	1.470	1.210	1.107	1.262	1500	0.772	0.563	1.467	1.210	1.107	1.262
2000	0.818	0.556	1.474	1.210	1.107	1.262	2000	0.789	0.555	1.470	1.210	1.107	1.262	2000	0.772	0.555	1.467	1.210	1.107	1.262
2500	0.818	0.555	1.474	1.210	1.107	1.262	2500	0.789	0.554	1.470	1.210	1.107	1.262	2500	0.772	0.553	1.467	1.210	1.107	1.262
3000	0.818	0.554	1.474	1.210	1.107	1.262	3000	0.789	0.553	1.470	1.210	1.107	1.262	3000	0.772	0.553	1.467	1.210	1.107	1.262
3500	0.818	0.553	1.474	1.210	1.107	1.262	3500	0.789	0.553	1.470	1.210	1.107	1.262	3500	0.772	0.552	1.467	1.210	1.107	1.262
4000	0.818	0.553	1.474	1.210	1.107	1.262	4000	0.789	0.552	1.470	1.210	1.107	1.262	4000	0.772	0.552	1.467	1.210	1.107	1.262
4500	0.818	0.552	1.474	1.210	1.107	1.262	4500	0.789	0.552	1.470	1.210	1.107	1.262	4500	0.772	0.552	1.467	1.210	1.107	1.262
5000	0.818	0.552	1.474	1.210	1.107	1.262	5000	0.789	0.552	1.470	1.210	1.107	1.262	5000	0.772	0.551	1.467	1.210	1.107	1.262

Length 100 km Terrain 100% Urban							Length 100 km Terrain 50% Urban							Length 100 km Terrain 0% Urban						
demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>			demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>			demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>		
kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road	kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road	kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road
500	0.947	0.601	1.495	1.313	1.107	1.361	500	0.889	0.593	1.487	1.313	1.107	1.361	500	0.855	0.586	1.482	1.313	1.107	1.361
1000	0.935	0.579	1.495	1.313	1.107	1.361	1000	0.877	0.575	1.487	1.313	1.107	1.361	1000	0.843	0.571	1.482	1.313	1.107	1.361
1500	0.935	0.571	1.495	1.313	1.107	1.361	1500	0.877	0.569	1.487	1.313	1.107	1.361	1500	0.843	0.566	1.482	1.313	1.107	1.361
2000	0.935	0.560	1.495	1.313	1.107	1.361	2000	0.877	0.559	1.487	1.313	1.107	1.361	2000	0.843	0.557	1.482	1.313	1.107	1.361
2500	0.935	0.558	1.495	1.313	1.107	1.361	2500	0.877	0.557	1.487	1.313	1.107	1.361	2500	0.843	0.555	1.482	1.313	1.107	1.361
3000	0.935	0.557	1.495	1.313	1.107	1.361	3000	0.877	0.556	1.487	1.313	1.107	1.361	3000	0.843	0.554	1.482	1.313	1.107	1.361
3500	0.935	0.556	1.495	1.313	1.107	1.361	3500	0.877	0.555	1.487	1.313	1.107	1.361	3500	0.843	0.554	1.482	1.313	1.107	1.361
4000	0.935	0.555	1.495	1.313	1.107	1.361	4000	0.877	0.554	1.487	1.313	1.107	1.361	4000	0.843	0.553	1.482	1.313	1.107	1.361
4500	0.935	0.554	1.495	1.313	1.107	1.361	4500	0.877	0.554	1.487	1.313	1.107	1.361	4500	0.843	0.553	1.482	1.313	1.107	1.361
5000	0.935	0.554	1.495	1.313	1.107	1.361	5000	0.877	0.553	1.487	1.313	1.107	1.361	5000	0.843	0.552	1.482	1.313	1.107	1.361

Length 150 km Terrain 100% Urban							Length 150 km Terrain 50% Urban							Length 150 km Terrain 0% Urban						
demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>			demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>			demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>		
kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road	kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road	kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road
500	1.063	0.617	1.517	1.417	1.107	1.460	500	0.977	0.607	1.504	1.417	1.107	1.460	500	0.926	0.596	1.496	1.417	1.107	1.460
1000	1.051	0.587	1.517	1.417	1.107	1.460	1000	0.965	0.581	1.504	1.417	1.107	1.460	1000	0.914	0.576	1.496	1.417	1.107	1.460
1500	1.051	0.577	1.517	1.417	1.107	1.460	1500	0.965	0.573	1.504	1.417	1.107	1.460	1500	0.914	0.570	1.496	1.417	1.107	1.460
2000	1.051	0.565	1.517	1.417	1.107	1.460	2000	0.965	0.562	1.504	1.417	1.107	1.460	2000	0.914	0.559	1.496	1.417	1.107	1.460
2500	1.051	0.562	1.517	1.417	1.107	1.460	2500	0.965	0.559	1.504	1.417	1.107	1.460	2500	0.914	0.557	1.496	1.417	1.107	1.460
3000	1.051	0.560	1.517	1.417	1.107	1.460	3000	0.965	0.558	1.504	1.417	1.107	1.460	3000	0.914	0.556	1.496	1.417	1.107	1.460
3500	1.051	0.558	1.517	1.417	1.107	1.460	3500	0.965	0.557	1.504	1.417	1.107	1.460	3500	0.914	0.555	1.496	1.417	1.107	1.460
4000	1.051	0.557	1.517	1.417	1.107	1.460	4000	0.965	0.556	1.504	1.417	1.107	1.460	4000	0.914	0.554	1.496	1.417	1.107	1.460
4500	1.051	0.556	1.517	1.417	1.107	1.460	4500	0.965	0.555	1.504	1.417	1.107	1.460	4500	0.914	0.554	1.496	1.417	1.107	1.460
5000	1.051	0.555	1.517	1.417	1.107	1.460	5000	0.965	0.554	1.504	1.417	1.107	1.460	5000	0.914	0.553	1.496	1.417	1.107	1.460

Length 200 km Terrain 100% Urban							Length 200 km Terrain 50% Urban							Length 200 km Terrain 0% Urban						
demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>			demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>			demand	Costs £ / kg H <sub>2</sub>			Emissions kgCO <sub>2</sub> / kg H <sub>2</sub>		
kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road	kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road	kg/day	Gas Road	Gas Pipe	Liquid road	Gas Road	Gas Pipe	Liquid road
500	1.180	0.634	1.538	1.520	1.107	1.559	500	1.064	0.620	1.520	1.520	1.107	1.559	500	0.996	0.605	1.510	1.520	1.107	1.559
1000	1.168	0.595	1.538	1.520	1.107	1.559	1000	1.052	0.580											



## References

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